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PENN WEST
ENERGY TRUST
2005 ANNUAL REPORT



THINK
BIG



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THINK BIG ENERGY

99,807_{boe/day}

AVERAGE DAILY PRODUCTION

360_{mmboe}

PROVED + PROBABLE RESERVES

As the largest conventional oil and natural gas producing trust in North America, Penn West has a high quality base of production and long-life reserves diversified by geography, size, capital intensity, commodity and play type. Penn West's large scale mitigates risks and contributes to stability and sustainability.



THINK BIG PEOPLE

327

HEAD OFFICE STAFF

381

FIELD STAFF

Penn West is an actively managed trust that reinvests a substantial proportion of operating cash flow to pursue new value through development of its asset base. That means Penn West's people are key to maintaining and adding value for unitholders.



Penn West employees at the Trust's Drayton Valley office

Left to right:
Pumping well at Pembina
CO₂ oil facility
Minnehik-Buck Lake gas plant
control room



We are aiming for top performance within the energy trust sector.

Our team of over 700 employees in the field and the Calgary head office drive the continued strong performance of our high quality assets. Penn West's senior management team includes members who guided the exponential growth of Penn West from a junior explorer to a highly profitable senior independent, then led the May 2005 trust conversion. Our 12-year track record of success was recently complemented by the Trust's implementation of an operating team organizational structure, which encourages innovative thought and multi-disciplinary project development.

THINK BIG VALUE

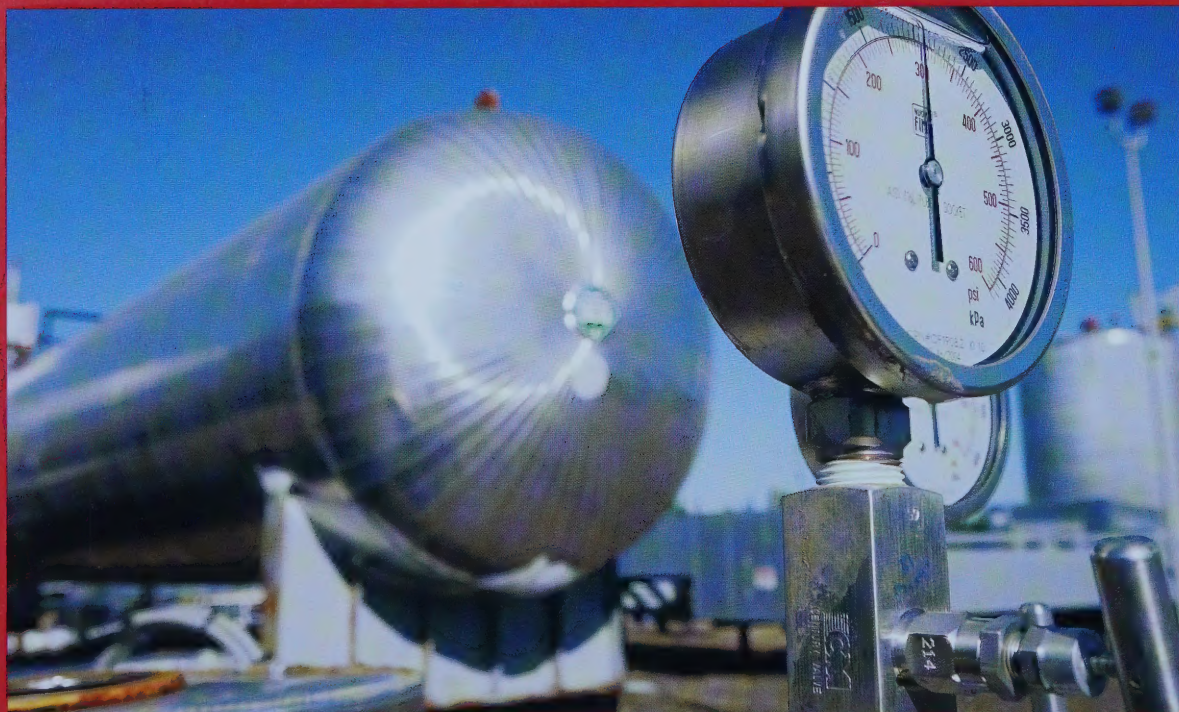
36.2%

2005 RETURN ON
CAPITAL EMPLOYED

\$0.34

MONTHLY DISTRIBUTIONS
PER UNIT

Penn West's high quality asset base generates the cash flows needed for the Trust to meet its distributions target. Distributions per unit have increased by 30 percent since the Trust's inception, to a rate of \$0.34 per unit, effective for our February 2006 distribution.



Left to right:
Pembina CO₂ bullets
Field employee in Drayton Valley
Pembina CO₂ pilot production tanks



\$1.2 billion

2005 CASH FLOW

43%

PAYOUT RATIO
FROM CONVERSION TO
YEAR-END 2005

\$6.2 billion

YEAR-END 2005 MARKET
CAPITALIZATION

Penn West has substantial competitive advantages in pursuing stable distributions and long-term value for unitholders. Trust operations emphasize operating cost control and capital efficiencies to ensure positive financial results from every dollar invested. With approximately 38 percent ownership of the immense, long-life Pembina Cardium field in west central Alberta, the Trust's unitholders can participate in a long-term project to potentially add hundreds of millions of barrels of new reserves. Penn West's multi-million-acre inventory of undeveloped land is a unique source of future value. The Trust has secured deals for farm-in partners to explore and develop more than 600,000 acres at no future cost to unitholders. Penn West's strong balance sheet, including its low debt ratio, positions the Trust for future strategic or accretive acquisitions.

SELECTED HIGHLIGHTS

FINANCIAL (\$ millions, except per unit amounts and % change)

Years ended December 31,	2005	2004 ⁽¹⁾	% change
Gross revenues	1,919.0	1,521.3	26
Cash flow ⁽²⁾	1,184.6	866.7	37
Basic per unit	7.28	5.37	36
Diluted per unit	7.14	5.28	35
Net income	577.2	271.8	112
Basic per unit	3.55	1.68	111
Diluted per unit	3.48	1.65	111
Distributions and dividends declared	332.3	26.8	1,140
Capital expenditures, net	456.7	865.6	(47)
Bank indebtedness	542.0	503.1	8
Unitholders' equity	2,172.2	1,909.0	14
Total assets	3,967.1	3,867.4	3
Units outstanding (millions)			
Weighted average			
Basic	162.6	161.4	1
Diluted	165.9	164.4	1
Year-end			
Basic	163.3	161.6	1
Basic plus trust unit rights	172.7	172.8	—

OPERATING

Years ended December 31,	2005	2004	% change
Production — annual average			
Light oil and natural gas liquids (bbbls/day)	33,137	34,943	(5)
Conventional heavy oil (bbbls/day)	18,705	18,136	3
Total liquids (bbbls/day)	51,842	53,079	(2)
Natural gas (mmcf/day)	287.8	316.3	(9)
Total production (boe/day)	99,807	105,788	(6)
Proved plus probable reserves ⁽³⁾			
Oil and natural gas liquids (mmbbls)	241	240	—
Natural gas (bcf)	698	761	(8)
Total reserves (mmbboe)	357	366	(2)
Wells drilled			
Gross	287	439	(35)
Net	276	417	(34)

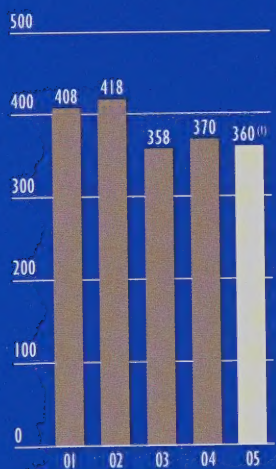
⁽¹⁾ Certain comparative per unit figures have been restated to reflect the conversion ratio of three trust units for each Penn West common share pursuant to the Plan of Arrangement.

⁽²⁾ Cash flow is a non-generally accepted accounting principles measure. For the Trust's calculation of cash flow, refer to Management's Discussion and Analysis.

⁽³⁾ Company interest reserves before royalty burdens and excluding royalty interest, at year-end.

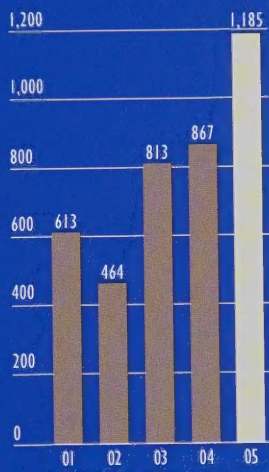
THINK BIG PERFORMANCE

As an exploration and production company, Penn West Petroleum Ltd. delivered growth in production, reserves, cash flow and share price to create shareholder value. As an energy trust, Penn West focuses on maintaining value for unitholders over the long term. Performance means sustainable production, reserves, cash flow and distributions.

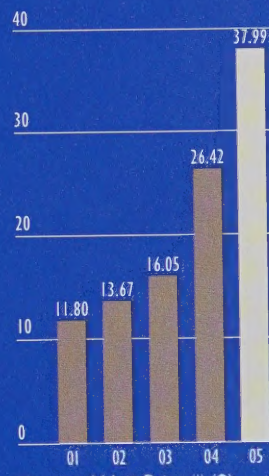


Proved + Probable Reserves at Year-end (mmboe)

⁽¹⁾ Working interest reserves before royalty burdens and including royalty interests.



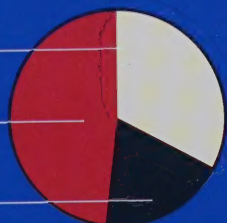
Cash Flow (\$ millions)



Year-end Unit Price ⁽¹⁾ (\$)

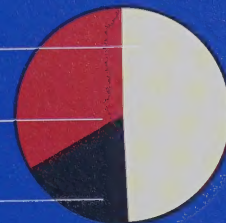
⁽¹⁾ The 2004 and prior years' comparative figures have been restated to reflect the conversion ratio of three trust units issued for each Penn West common share pursuant to the Plan of Arrangement.

Light Oil & NGL 33,100
Natural Gas 48,000
Heavy Oil 18,700



2005 Average Production Profile (boe/d)

Light Oil & NGL 178
Natural Gas 118
Heavy Oil 63



Year-End 2005 Proved + Probable Reserves Profile (mmboe)

PENN WEST ENERGY TRUST OFFICERS



Back row left to right:
Kristian Tange, VP Business Development
Gregg Gegunde, VP Development
William Andrew, President and CEO
David Middleton, Executive Vice President and COO
Thane Jensen, Senior VP Exploration and Development

Front row left to right:
William Tang Kong, VP Corporate Development
Anne Thomson, VP Exploration
Todd Takeyasu, VP Finance
Eric Obreiter, VP Production

President and CEO's Letter

FELLOW UNITHOLDERS

Penn West Energy Trust is the largest conventional oil and natural gas producing trust in North America, with production averaging 99,800 boe per day in 2005. Penn West Energy Trust's objective is to be one of North America's top performing energy trusts as measured by production and reserves performance per unit, by the stability of our cash distributions to unitholders, and by our maintenance of long-term value for unitholders.

Our first seven months as an energy trust speak positively. Cash flow from June 1 to December 31, 2005 totalled \$744 million or \$4.58 per unit, basic. Our active program of internal development focused on low risk opportunities and maintaining production. Monthly distributions commenced in July 2005 at \$0.26 per unit, increased to \$0.31 per unit in November and are currently \$0.34 per unit. The 30 percent increase in distributions per unit reflects not only a strong commodity market, but also our belief that we are creating an efficient, high quality trust.

BUSINESS MODEL

All Canadian oil and natural gas trusts have interests in producing assets, and all distribute cash to unitholders. Within this broad model are varying characteristics that influence the individual trust's cash flow, capital and cost efficiencies, risk profile, sensitivity to commodity prices, ability to sustain production and reserves and, ultimately, the sustainability of the trust.

Penn West begins its era as an energy trust with substantial competitive advantages. These include: large scale, financial strength (including access to capital and a strong balance sheet), high quality diversified producing assets, extensive management

team experience, and depth in employee knowledge both in the field and head office.

These advantages have shaped our business model. Its key characteristics include the following:

- > Active management of operations;
- > Focus on stable distributions and maintaining value;
- > Reinvestment of a substantial proportion of operating cash flow to:
 - > Develop our large and diverse internal inventory of lower risk optimization, exploitation and development opportunities; and
 - > Develop large-scale projects offering strategic growth potential over the long term;
- > Focus on capital efficiencies;
- > Participation in exploration without capital risk through farm-out of undeveloped land; and
- > Pursuit of growth opportunities through accretive or strategic acquisitions.

OUR FOREMOST COMPETITIVE ADVANTAGE - OUTSTANDING ASSETS

Penn West's asset base is diversified in commodity, risk profile, geography, size, capital intensity and reserve life. It is balanced between properties offering short-term cash flow and maximum current production, and others with long-term, stable volumes. Our asset base holds a range of opportunities for development including infill drilling and horizontal drilling; facilities and systems optimization; high quality light oil pools with long-term future upside from pressure maintenance and enhanced recovery; natural gas exploration; and significant, undeveloped oil sands leases.

Four project areas are of strategic importance:

- > Penn West's Central Area contains 60 percent of our reserves and generates 42 percent of our production. With a long reserve life and a light oil product generating high netbacks, it is well suited to times of high or low commodity prices. It holds the majority of opportunities for enhanced oil recovery over the long term, making these assets key to the Trust;
- > Our Plains Area holds about 27 percent of reserves and produces about 38 percent of volumes. With year-round access and mainly shallower depth pools, this area offers short to medium term opportunities, such as infill and horizontal drilling, geared to immediate cash flow generation at low risk. The Plains Area also has potential for heavy oil enhanced recovery projects;
- > The Northern Area provides high netback, low operating cost natural gas volumes. It balances the Trust's asset mix through a multi-year opportunity base of higher impact opportunities for development drilling and natural gas exploration; and
- > Our Peace River oil sands project provides an opportunity to develop long life oil reserves at a low per unit finding and development cost.

OPERATING APPROACH

The risk profile and cash distribution mandate of an energy trust means that a trust does not normally attempt long-term internal growth in production and reserves. Because energy trusts drill on lower risk properties, with new wells expected to come on stream quickly, unitholders rightly expect high capital efficiencies. As a new trust, Penn West is implementing measures to ensure positive financial results from every new



Pembina CO₂ pilot project with CO₂ bullets in the background

dollar invested, as well as minimizing operating costs on a unit-of-production basis.

As a result of our 2005 strategic review, we made changes to our management team and methods. The shift included de-emphasizing top-down executive management and introducing an operating team concept placing greater responsibility at the core area team level. This encourages innovative thought, project development and team responsibility for planning, budgeting and execution. We are optimistic that this approach will provide improved capital efficiency, better operating cost control and a balanced inventory of prospects suited to the risk profile of an energy trust.

Since we have identified numerous internal development projects that span several years, the Trust is not under pressure to complete acquisitions. As an exploration and production company, Penn West successfully executed and integrated acquisitions, from small producing properties to asset packages of several hundred million dollars, including counter cyclical transactions during low commodity and asset prices. As a trust, we will pursue acquisitions when we encounter the right strategic opportunities to strengthen our inventory of assets.

FARM-OUT OF EXPLORATION LANDS

Upon conversion to a trust, Penn West's inventory of undeveloped land – nearly 5 million net acres – was larger than that of some companies several times Penn West's size. Rebalancing our risk profile to the needs of a trust, and identifying

undeveloped lands complementary to our development properties, created a surplus land inventory of 1.5-2.0 million net acres.

There is currently strong demand for exploratory acreage from the many growth-oriented junior E&P companies as well as from established larger companies. Oil and natural gas drilling in Western Canada set a new record in 2005, and is forecast to grow by a further 15+ percent this year. Crown land sales continue to yield strong bids. We believe our undeveloped land represents an excellent source of incremental production and cash flow with no further commitment of the Trust's capital. For exploration oriented companies, the attractions of Penn West's available land include detailed seismic information, preliminary geological work and large contiguous blocks.

The work of converting this land into a future income stream began on June 1, 2005. We commenced farming out parcels of lands to exploration focused companies. In return for an interest in the lands and future production, these companies conduct drilling, completion and tie-in operations at their expense.

To date, we have secured deals for farm-in partners to actively explore and develop more than 600,000 net acres. We foresee companies drilling approximately 100-200 wells in the near term, with further drilling and development triggered by success. We envision continued strong interest in our land and we plan to extend this process until as much of the surplus acreage as possible is farmed out.



Pembina CO₂ pilot inlet piping/header

Most of the agreements call for Penn West to receive a non-convertible gross overriding royalty interest in future production, with no deductions for processing. In plain terms this means that, without placing any unitholders' capital at risk, the Trust stands to gain a new stream of production and cash flow in the years ahead, supplementing our distributable cash and increasing our operational flexibility.

LONG-TERM INTERNAL GROWTH OPPORTUNITIES

Growing an energy trust in production and cash flow generally requires significant acquisitions funded by external debt and equity capital, making it challenging to achieve growth on a per unit basis. Of primary importance to Penn West are two projects capable of substantial long-term growth in reserves and production, with a risk profile suited to an energy trust. These internal projects hold potential to add significant value for unitholders.

Penn West controls approximately 38 percent of the immense, long life Pembina Cardium field in west central Alberta, the largest conventional light oil pool ever discovered in Canada. Following a series of acquisitions in the 1990s, Penn West began to invest in revitalizing the field by implementing pressure maintenance through water injection and by down spacing the wells.

With a total resource estimated at 7.8 billion barrels of original-oil-in-place, of which only 17 percent is recovered to date, the Pembina Cardium field is a prime candidate for tertiary or enhanced oil recovery. Penn West intends to

utilize carbon dioxide byproduct from heavy industry in Alberta, injecting it as a “miscible” agent to access known but unrecovered oil-in-place. The potential for incremental reserves and production is significant. Penn West initiated a grassroots, pilot scale carbon dioxide injection project at Pembina approximately one year ago. Moving forward, the first commercial scale phase of Pembina CO₂ development will require capital expenditures of \$200-\$285 million through 2009. Full scale development could ultimately involve 10 to 12 future phases.



Penn West water injection facility

The other long-term project is in the Peace River oil sands in northern Alberta. Unusual for an oil sands project, the horizontal wells drilled into this bitumen deposit can initially produce through lower cost “cold pumping,” without the application of external heat or steam. Longer term recovery will likely require thermal techniques. Penn West’s pilot scale project is currently producing approximately 900 barrels per day. The capital requirement to bring Seal to production of an estimated 20,000 barrels per day over 2006-2010 will be \$350-\$400 million. One challenge is the area’s sparse infrastructure, which we plan to overcome through the acquisition of interests in a central processing facility and sales oil pipeline.

Over the next few years, Penn West anticipates investing significant capital in these long life projects. The capital expenditures required over the next few years are expected to lead to significant production growth and to enhance unitholder value over the long term.

Results from long-term projects will be measured over years, versus quarter over quarter. Penn West anticipates capital expenditures on these multi-year projects to approximate 50 percent of the Trust’s total annual capital budget over each of the next few years.

ACCESS TO CAPITAL AND TAX EXPOSURE

At Penn West Energy Trust, we emphasize maintaining a clean balance sheet that enables us to make substantial strategic acquisitions and to have future sources of capital when cash flow alone might not finance a major project. With available bank lines totalling \$1.2 billion and year-end debt of \$542 million – less than 0.5 times 2005 cash flow – Penn West had no external capital requirements during 2005. Penn West Petroleum Ltd. had not executed an equity issue since 1999.

Strong commodity prices and cash flows, when combined with internal retention of a significant proportion of cash flow, can expose an income trust’s operating corporation to income tax. For 2006, we foresee no current income tax liability.

DISTRIBUTIONS APPROACH: AIMING FOR STABILITY

Cash distributions are a crucial attribute of any income trust. Penn West Energy Trust opened with a monthly distribution rate of \$0.26 per unit in July 2005. This level was based on our best estimates of future production, commodity prices, operating costs, capital efficiencies and cash flow at the time of conversion. As the management team became more confident operating under the new capital structure and management approach, we re-examined the same factors. We raised the distribution level to \$0.31 per unit in November and again in March 2006 to \$0.34 per unit.

The new level, announced in February 2006, represents approximately 60 percent of our estimated 2006 cash flow. We will continue to monitor key variables, including future price strips, capital efficiencies, capital requirements, netbacks and production levels, in order to maintain as stable a distribution rate as possible within the context of the trust model that aims to support long-term distributions.

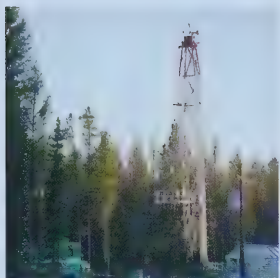
We can reduce the uncertainties associated with future operations through commodity price hedging and fixing the cost of certain elements of our operating costs. For an income trust, hedging increases the predictability of future cash flows, helping to stabilize distributions. Since converting to a trust, we have aggressively hedged oil and natural gas volumes. We have also secured hedges to fix the costs of electric power at our oilfield operations, improving our ability to project future netbacks and cash flows.

With world oil prices and North American natural gas prices at record levels in 2005, we utilized our 2005 cash flow to fully fund our capital program and distributions. In addition, we repaid all debt incurred at the time of the trust conversion for the payment of income taxes and to cancel the former stock option plan. We exited 2005 with lower total debt than in 2004.

Penn West Energy Trust is committed to the well-being of our employees, our communities and the land that we utilize while we pursue oil and natural gas exploration and development. We have an active Health, Safety and Environment program and a Community Outreach Program that commits us to demonstrate leadership in safety, in environmental stewardship and in community involvement.

2006 OUTLOOK

Our outlook for 2006 is positive. Commodity prices remain relatively high, and Penn West's budget is based on average benchmark prices of US\$58.00 per barrel of West



Service rig in Drayton Valley area

Texas Intermediate crude oil and \$8.75 per thousand cubic feet of natural gas at AECO, with an average currency exchange rate of \$0.85 CAD/USD and an average effective interest rate of 4.25 percent.

Penn West's assets continue to generate robust volumes which, supported by our internal development program of 250-300 net wells, are forecast to average 94,000-98,000 boe per day in 2006. Our capital program is budgeted at \$400-\$500 million and will target development, optimization and continued work on long-term growth projects. Planned capital expenditures are approximately 40-45 percent of our forecast cash flow of \$1.0-\$1.1 billion.

At this time, I wish to extend thanks to all of Penn West Energy Trust's employees – new members of the team as well as those who worked through the conversion with an aim to build the strongest energy trust in Canada. Your dedicated efforts helped make our trust conversion and operations a success. Thanks also to Penn West's Board of Directors, and to our evolving and growing base of unitholders. I look forward to 2006 and beyond with optimism.

On behalf of the Board of Directors,

A handwritten signature in dark ink, appearing to read 'William Andrew'.

William Andrew
President and Chief Executive Officer

February 27, 2006

THINK BIG FUTURE

9.9 years

RESERVE LIFE
(proved + probable)

4.1 million net acres

UNDEVELOPED LAND

Penn West's asset base is diversified by commodity, geographical region and risk profile. Cash flow maximizing oil and natural gas properties are balanced by longer life properties with lower declines. Penn West's extensive inventory of internal opportunities includes short term exploitation and optimization, medium term development drilling, and long-term enhanced recovery and oil sands projects.



Left to right:
 Minnehik-Buck Lake inlet
 compression facility
 Minnehik-Buck Lake
 gas plant – NGL bullet
 Minnehik-Buck Lake
 process piping



Operations Review

Maximize

SHORT TERM

With three core areas in the Western Canada Sedimentary Basin, active management and technical expertise, Penn West continually pursues opportunities that generate a rapid cash flow response and fast capital payout, while continually striving to improve capital efficiency.

Manage

MEDIUM TERM

Penn West plans to add unitholder value through development drilling, carefully targeted exploration and monetization of its immense base of undeveloped land through farm-outs to exploration companies in return for royalty participation in future production.

Enhance

LONG TERM

Important legacy properties are the Pembina Cardium light oil pool and the Peace River oil sands leases. These hold potential for substantial long-term growth in reserves and production – and value for unitholders – within an energy trust risk profile.

Maximize

Conventional oil and natural gas opportunities

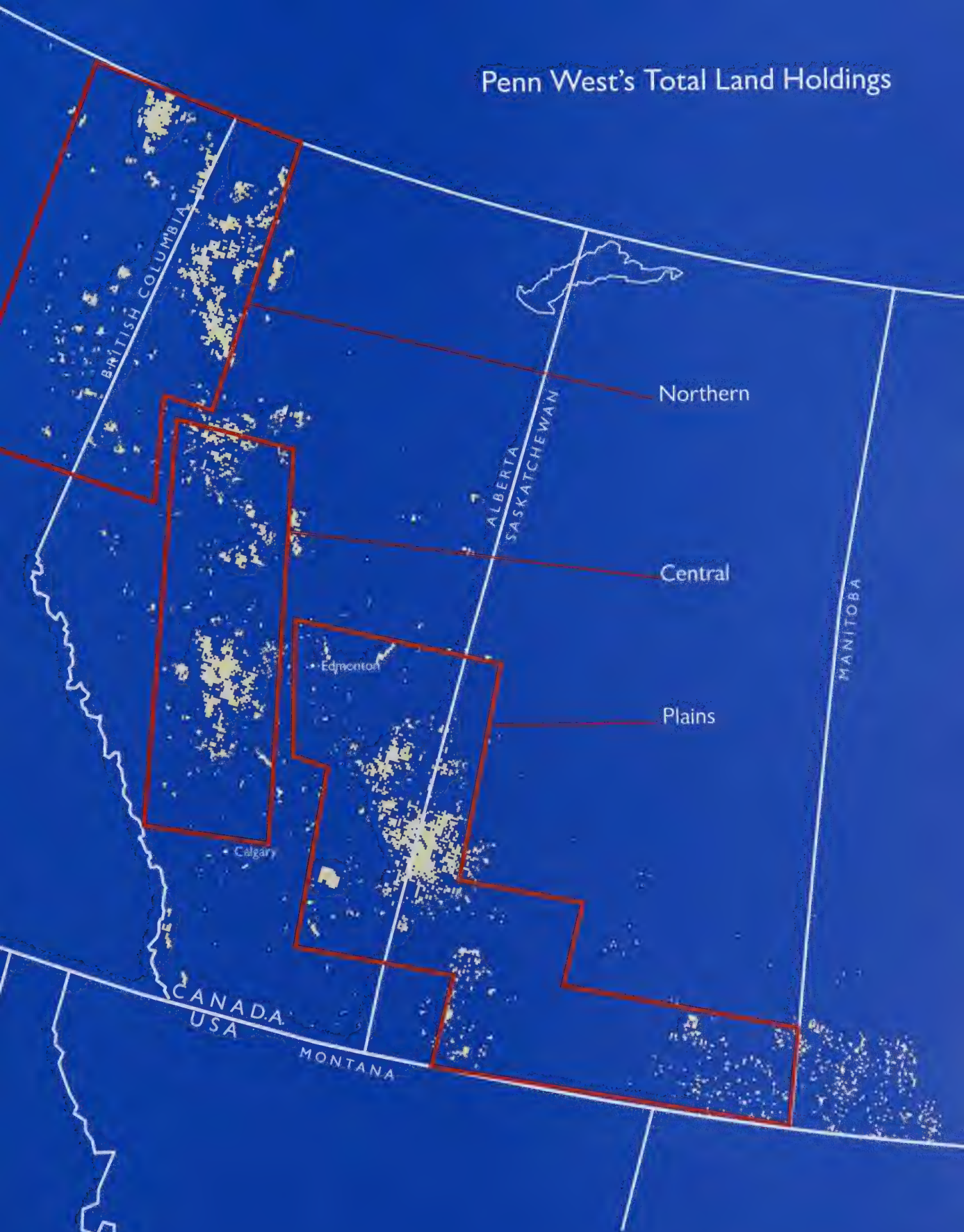
In 2006, Penn West has a budgeted \$400-500 million capital program to pursue capital efficient opportunities that lever existing Trust infrastructure including: field optimization, suspended well reactivations, plant consolidation, well stimulations and recompletions, and low risk infill drilling, down spacing and horizontal drilling.

	2005 Average Daily Production			Proved Plus Probable Reserves at December 31, 2005 ⁽¹⁾			At December 31, 2005	
	Liquids ⁽²⁾ (bbls/day)	Natural Gas (mmcf/day)	Total (boe/d)	Liquids ⁽²⁾ (mmbbls)	Natural Gas (bcf)	Total (mmboe)	Reserve Life Index (P+P) (years)	Undeveloped Land (000 net acres)
Central	25,768	94	41,440	168.0	295	217	14.3	848
Plains	25,353	74	37,739	71.4	152	97	7.0	1,406
Northern	721	120	20,628	2.2	261	46	6.1	1,888
	51,842	288	99,807	241.6	708	360	9.9	4,142
	52% of daily production	48% of daily production		67% of total reserves	33% of total reserves			

⁽¹⁾ Working interest reserves before royalty burdens and including royalty interests.

⁽²⁾ Includes crude oil and natural gas liquids.

Penn West's Total Land Holdings



Central Area

Penn West's Central Area accounts for approximately 60 percent of the Trust's reserves and 40 percent of its production. Average 2005 volumes were approximately 41,400 boe/day, of which 38 percent was natural gas. With long reserve life and a high netback light oil product, the Central Area is well suited to times of both high and low commodity prices.

Pembina

The Trust's largest Central Area property group, Pembina, produces a mix of light, sweet, high netback crude oil and shallow to medium depth natural gas plus NGL. The field's main oil producing formation is the immense Cardium light oil pool, under secondary recovery through an extensive waterflood program. Penn West's focus is to continue down spacing the field's well density towards 80 acres and ultimately 40 acres. Penn West drilled 19 Cardium oil wells in 2005 and plans to drill an additional 25 wells in 2006. Infill drilling accesses additional reservoir area, increasing recovery with very low risk, and extends the field's productive life, currently estimated at greater than 50 years.

Pembina holds additional oil opportunities in the Pekisko and Nisku formations. A three well Pekisko program executed in 2005 achieved 100 percent success, adding 150 barrels per day of oil plus natural gas. The area also continues to yield prolific natural gas discoveries, and the Trust has plans for six deep natural gas wells in 2006. Natural gas opportunities include the shallow Edmonton Formation and deeper targets in the Mannville and Fernie Groups.



Pembina CO₂ pilot tank farm

Willesden Green

Penn West's Willesden Green property in West Central Alberta provides a base of light oil and natural gas production that can be kept stable by optimization work and modest drilling to replace annual declines. Production averaged 11,200 boe per day in 2005.

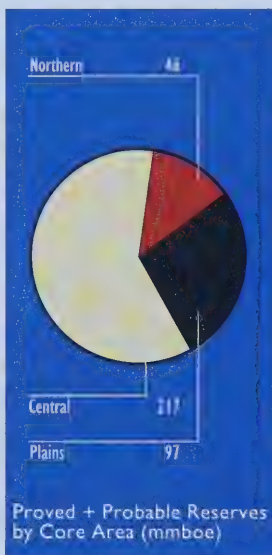
Willesden Green continues to offer a mix of future drilling and optimization opportunities including drilling Cardium oil and natural gas wells, as well as shallow Edmonton natural gas plays. Optimization opportunities include well reactivations and uphole recompletions, compression/pipeline optimization and re-fracturing of the Cardium and Belly River oil zones. The development and operations staff evaluate all projects with an emphasis on capital efficiency and operating cost reduction. The Trust has

budgeted \$20 million to drill, complete and tie-in 17 wells in 2006, including a four-well 40-acre spacing Cardium pilot which, if successful, could be replicated numerous times over.

Swan Hills

This light oil pool was under enhanced recovery through hydrocarbon miscible flooding combined with waterflood. Production is currently 2,600 barrels per day of oil, 600 barrels per day of NGL and 4 mmcf per day of natural gas. Penn West plans to resume hydrocarbon injection in 2006.

Swan Hills is also prospective for coalbed methane (CBM) development. Using horizontal wells radiating from a common pad, area competitors have observed a dewatering phase of less than three months followed by steady natural gas production averaging 200-300 mcf per day per well. Penn West plans a four-well (Mannville) horizontal CBM



pilot project in the second quarter of 2006. The Trust will exploit existing infrastructure to maximize capital efficiencies.

Plains Area

Hoosier, Wainwright and South Plains in the Alberta/Saskatchewan border region form the Trust's second-largest base of production and main opportunity area for low risk, low cost production additions. The year round access region averaged approximately 37,700 boe per day in 2005 (about 66 percent conventional heavy crude oil and 34 percent shallow to medium depth natural gas).

Penn West's strength in land and infrastructure, its high average working interests and the multi-zone nature of drilling targets create a combination of low risk, high success rates, high capital efficiencies and strong cash flow.

Exploitation activities include optimization, waterflood enhancement, well recompletions, infill drilling and new drilling, all leveraging existing Penn West gas plants, oil batteries and pipelines. Penn West also has 700 suspended wells in the Plains Area, some of which will be reactivated or recompleted to take advantage of current high commodity prices.

The 2005 capital program included 182 net wells. Six horizontal exploration wells targeting six different play types, which flowed at initial rates of up to 300 barrels per day, will be followed up in 2006 with additional low risk development. The 2006 capital program of \$140 million will include about 160 wells.



Pembina CO₂ pilot compression and master control buildings

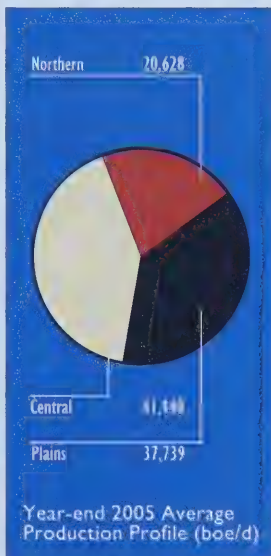
As part of Penn West's operating cost reduction focus, 25 wells were electrified in 2005 and a further 400 to 500 wells will be converted from propane or gas in 2006.

Northern Area

The Northern Area provides a base of high netback natural gas production equivalent in size to an intermediate exploration company. It was developed by Penn West through grassroots exploration, production growth and infrastructure development over the previous 10 years. The Trust's focus is to maintain average volumes of in excess of 100 mmcf per day at high capital efficiency.

Penn West's competitive advantages include core properties with a long track record of success, an extensive geological database, high ownership infrastructure, and large undeveloped land areas. These create a favourable combination of low risk, high success rates, fast payout and strong returns. The Northern Area contains an opportunity base for higher impact natural gas development plus carefully targeted exploration. The region's capital program for winter 2005-2006 totals \$66 million and includes up to 36 wells plus numerous optimization initiatives.

At Wildboy, the Northern Area's largest property, the Trust is adding field compression and fluid handling capability while continuing to plan development drilling. At Firebird, Penn West is extending its successful Notikewin gas play while optimizing its gas plant to handle condensate. At Boyer, the Trust is focused on improving well performance through hydraulic fracturing of producing zones and installing plunger lift systems to improve water evacuation, while reducing operating costs by consolidating gas plants.



Manage

Undeveloped land opportunities

Upon Penn West's conversion to a trust in May 2005, the Trust had approximately 5 million net acres of undeveloped land – the largest land base of any Canadian energy trust. Penn West is utilizing this land base to create future upside for unitholders by farming out prospective undeveloped lands to growth oriented oil and gas companies.



New Farm-out Wells Drilled



Farm-out Deals Completed



Net Acres Farmed Out (000)

Northern Area: The largest area for farm-out activity due to the size of Penn West's land holdings and the wide range of play types and risk profiles.

Central Area: Lands for farm-out tend to be exploratory in nature with high impact, multi-zone potential.

Plains Area: Farm-out packages are suitable for companies that favour smaller plays, all season access and lower risk.



Key Farm-out Blocks

600,000

net acres

FARMED OUT BY PENN WEST TO MARCH 2006

Penn West's immense land holdings are highly prospective for oil and natural gas exploration and development. When Penn West converted to a trust in May 2005, the Trust held almost 5 million net acres of undeveloped land with an average working interest of 94 percent. As a result of the conversion to a trust structure, Penn West decided to adjust its plans and establish a more conservative risk profile appropriate for a trust, emphasizing long-term distributions to unitholders.

Penn West will continue to be active in the drilling and development of its core areas. The Trust will also monetize a significant portion of its land assets by farming out non-core, capital intensive and higher risk properties to growth oriented exploration and development companies. These companies require undeveloped land to drill for new reserves and production to drive their own growth.

Penn West plans to offer up to 2.0 million net acres of prospective land for farm-out opportunities. The farm-out

agreements will typically provide Penn West with a non-convertible gross overriding royalty on any new production derived from exploring and developing the farmed out lands. The partner incurs the costs associated with exploration, development, production and processing. This approach could provide Penn West unitholders with a new stream of production and cash flow in the years ahead without risking additional capital or current distributions.

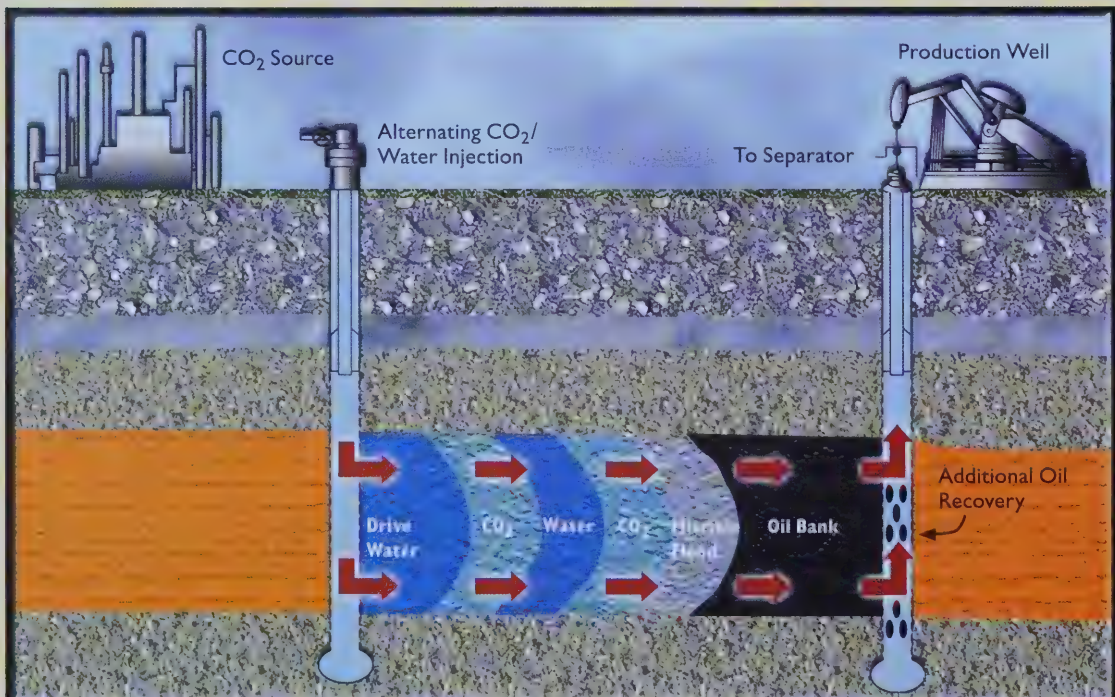
As of March 2006, Penn West had concluded farm-out agreements covering more than 600,000 net acres of undeveloped land. These agreements include large area, multi-well commitments that could see the drilling of 100-200 wells per year in the future, with further drilling and development being triggered by the success of the initial wells. Penn West believes there will be continued strong interest in its farm-out opportunities, which could become an excellent source of future production and cash flow.

Enhance

Maximize future returns to unitholders through long-term, grassroots enhanced oil recovery and oil sands projects

Penn West has two major project areas that are capable of driving the Trust's growth over the long term. The Pembina Cardium enhanced oil recovery project could yield 150-400 million barrels of new reserves, and the Peace River oil sands project is targeted to add volumes of nearly 20,000 barrels per day over the next five years.

Enhanced Oil Recovery (EOR) Using Carbon Dioxide Miscible Flooding Technology



Top 15 Light/Medium Oil Pools in Alberta (Ranked by original-oil-in-place (OOIP))

Rank	Pool	Formation	API°	OOIP (million bbls)	Cumulative Production to the End of 2004 (million bbls)	Percent Recovery to the End of 2004 (%)	Approx. Penn West Interest (%)	Amenable to Enhanced Recovery with CO ₂
1	Pembina	Cardium	38	7,793	1,228	15.8	38	Yes
2	Swan Hills	BHL	41	3,454	1,241	35.9	25	Yes
3	Redwater	D3	36	1,304	829	63.6	20	Unknown
4	Judy Creek	BHL	41	1,045	464	44.4	—	
5	Turner Valley	Rundle	40	1,002	157	15.7	—	
6	Twining	Rundle	30	912	39	4.3	—	
7	Willesden Green	Cardium	41	892	137	15.4	30	Unknown
8	Nipisi	Gilwood	41	820	350	42.7		
9	Bonnie Glen	D3A	42	788	521	66.1	—	
10	Mitsue	Gilwood	43	775	382	49.3	35	Yes
11	Ferrier	Cardium	44	611	76	12.4	—	
12	Pembina	Belly River	37	529	104	19.7	—	
13	Fenn Big Valley	D2A	32	504	310	61.5	—	
14	Virginia Hills	BHL	38	485	171	35.3	35	Yes
15	Wizard Lake	D3	38	402	213	53.0	—	

Source : " Alberta's Reserves 2004 and Supply/ Demand Outlook 2005-2014", EUB, 2005

CO₂ Miscible Flood Enhanced Oil Recovery

Pembina Cardium

By adding an estimated 150-400 million barrels of net new reserves, the Pembina Cardium CO₂ miscible flood project could generate significant asset value, cash flow and distributions for Penn West's unitholders over the long term. The project's estimated capital needs of \$500 million over five years, including up to \$300 million over the first three years, would be met through a combination of internal cash flow and external debt and, possibly, equity financing.

Through a series of acquisitions in the 1990s, Penn West owns an average net working interest of 38 percent of the

Pembina Cardium oil pool in west central Alberta. With an estimated 7.8 billion barrels of original-oil-in-place, it is the largest conventional light oil pool ever discovered in Canada. Although producing for more than 50 years, the Pembina Cardium pool has only produced approximately 17 percent of its original-oil-in-place to date and has at least 50 years of remaining economic life using EOR techniques.

A significant portion of the pool appears amenable to carbon dioxide (CO₂) miscible flooding (see schematic, page 22), an enhanced or tertiary recovery technology that could significantly increase recoveries of known resources-in-place above currently booked reserves. Given the pool's immense size, each percentage point increase in recovery of original-oil-in-place represents approximately 30 million barrels of light oil reserves to Penn West at our current working interest.

Joffre learning project – In 2001, Penn West acquired the Joffre project – the only commercial CO₂ miscible flood in Alberta, and the first in Canada. With secondary production completely shut-in during the 1970s, Joffre's response to CO₂ miscible flooding has been very positive, with production climbing from zero in 1983 to 900 barrels per day in 2000 (see chart below). A dormant field with essentially zero value became a growth play with the application of tertiary recovery technology.



Proposed CO₂ pipeline

miscible flood pilot on a technically representative portion of the Pembina Cardium pool. The pilot was activated in March 2005. Although it is still early in the expected life of the pilot, reservoir response has been within expectations.

The pilot's goal is to substantiate the viability of a commercial scale CO₂ miscible flood to be applied field wide in multiple phases over many years. The Trust's technical team is conducting a detailed analysis of the Pembina Cardium

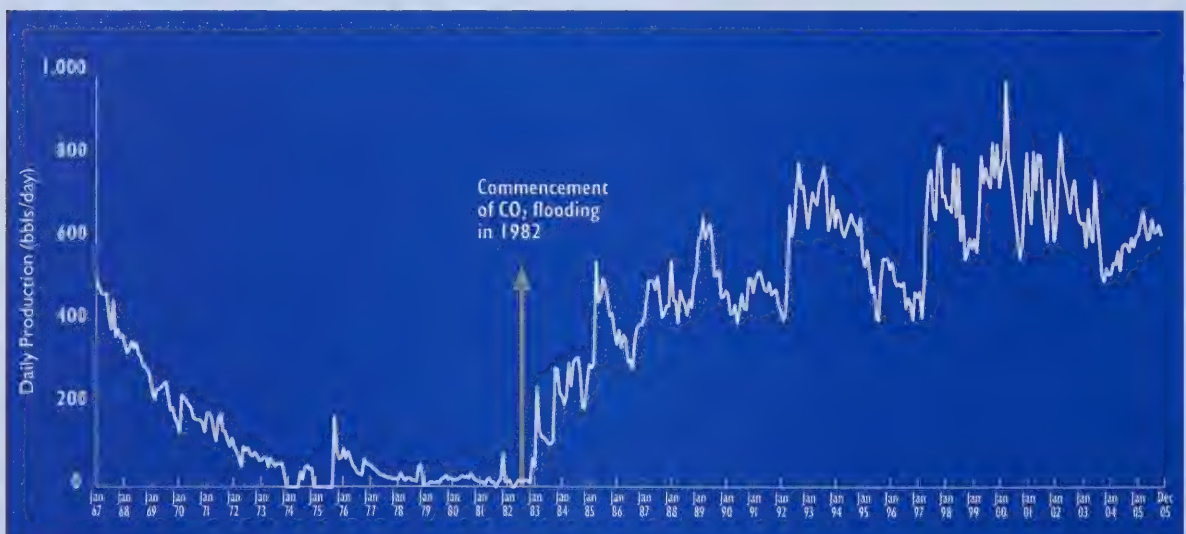
pool to identify areas suitable to CO₂ miscible flooding.

Joffre's principal function for Penn West has been to provide operating experience and technical data to apply to the much larger Pembina Cardium project. Joffre's conventional production, including waterflood, has yielded 18.3 million barrels of cumulative production. The miscible flood to date has added 4 million barrels. Penn West foresees a further 2 million barrels under expanded CO₂ miscible flooding, which is anticipated to begin in 2006.

Pembina Cardium pilot – Levering experience gained at Joffre, Penn West constructed a 100 percent owned CO₂

CO₂ supply – The acquisition and transportation of a large volume of CO₂ at a reasonable cost is the key to a successful commercial scale project. Over 70 U.S. oil fields have commercially successful CO₂ miscible floods using naturally occurring underground CO₂. In order to also generate environmental benefits, Penn West intends to source CO₂ from a large industrial emitter. CO₂ would be captured in Alberta, transported via pipeline (see map), and permanently "sequestered" through injection into the Pembina Cardium reservoir.

Joffre CO₂ Miscible Flood



To optimize production, the Pembina Cardium CO₂ miscible flood would include the drilling of new wells throughout the suitable pool areas on reduced spacing. Full field development would encompass numerous development phases. Based on current project scoping, incremental oil production is expected to peak at an estimated 5,000-8,000 barrels per day per phase.

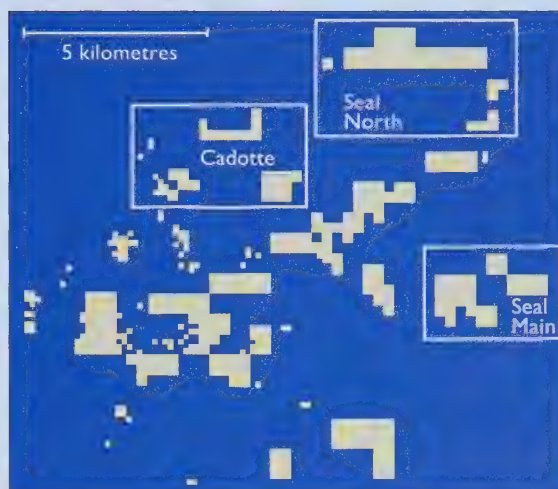
Peace River Oil Sands Project

The Peace River oil sands project provides an opportunity to significantly enhance value and distributions to Trust unitholders over the long term. Penn West holds 100 percent working interest in oil sands rights covering over 200,000 net acres concentrated at three properties – Seal Main, Seal North and Cadotte.

Prior to 2005, Penn West had drilled 26 horizontal wells at Seal Main to substantiate its operating and business model. Production has currently reached 900 barrels per day and capital efficiencies on a going forward basis are estimated to be \$12,000-\$15,000 per daily flowing barrel – one of the highest capital efficiencies of any Penn West project.

In 2006, Penn West is accelerating activity with a 24-well horizontal program at Seal Main targeting production of 2,500-3,000 barrels per day. The Trust will also initiate drilling at Cadotte and Seal North, with 25 wells forecast to add 2,500 to 3,000 barrels per day. Capital expenditures for 2006 are estimated at \$80 to \$90 million, which will include a portion of the acquisition of an oil processing facility, a sales oil pipeline at Seal Main and the acquisition of over 80,000 acres of oil sands leases.

The reservoir rock's high permeability, combined with the oil's relatively low viscosity, allows production to be "cold pumped". Penn West plans to maintain reservoir pressure and



Peace River oil sands project

production rates by conventional waterflood in the near term. In the future, a thermal recovery scheme could be developed to significantly increase production and reserves, as the region is highly prospective for underground, or in situ, oil sands recovery from the Bluesky Formation.

The Peace River oil sands project holds a massive resource base of several billion barrels of oil-in-place. Planning is underway to transform this resource into long life reserves, generating production of 20,000 barrels per day. This will require drilling about 65 wells per year for five years, plus constructing or acquiring a complete gathering system and sales pipeline. The estimated capital requirements of the project over the next five years, totalling approximately \$350-\$400 million, would be funded through a combination of internal cash flow plus new debt and, possibly, new equity.

Health, Safety, Environment and Community Initiatives

Health and Safety

Safety is an integral part of Penn West Energy Trust's business. Working safety plays a vital role in our operations and in our efforts to protect people and the environment. In 2005, Penn West renewed its focus on ensuring the health and safety of all employees and contractors' employees. Employees and contractors care that Penn West will not place production ahead of safety.

The Trust meets these obligations by providing the required resources and taking proactive measures to prevent incidents and the resulting injuries from occurring. Senior management plays an active role and is responsible for designing, coordinating, managing and improving the Trust's safety management systems.

Penn West has adopted the following principles:

- > Safety policies, procedures and programs developed by Penn West shall meet or exceed legislative requirements;
- > The Trust's management shall ensure compliance by establishing programs and conducting audits of its operations;
- > Compliance with safety policies and procedures is the responsibility of every employee and contractor, and is a condition of employment;
- > Any injury and any serious incident shall be reported and investigated; and
- > Employees and contractors who knowingly violate safety rules will face disciplinary action, dismissal or legal action.

The Trust was active in demonstrating and communicating health and safety throughout 2005. Senior management conducted safety stand-downs at various facilities throughout the year. This included eight town hall meetings to discuss Penn West's commitment to safety with more than 700 field employees and contractors.



Penn West safety training

Other areas of focus included collision prevention and safe driving initiatives. Penn West increased driver training, developed fleet safety standards, adopted a driver safety survey and implemented a program for the safe movement of vehicles on well sites. These actions helped our employees achieve a 40 percent decrease in vehicle collisions in 2005 from 2004. In March 2006, Penn West adopted a cell phone-free driving policy to prevent possible injury to employees and the public by reducing distractions while driving.

Penn West continued its focus on identifying potential safety hazards through employee and contractor safety behaviour observations, and the self-audit of our field operations for regulatory compliance. Penn West employees participated in over 3,700 of these activities, an increase of 28 percent over 2004. These activities and Penn West employees' commitment to a safe workplace helped contribute to a 23 percent decrease in recordable injuries from 2004 and a reduction in employee lost-time accidents to zero for 2005.

Also in 2005, Penn West initiated the Task Competency Assessment System, a software-supported process for the development of safe work procedures and assessment of operating staff to ensure that they can safely perform their job tasks. Penn West views this program as a multi-year commitment to the training and safety of its field employees.

Environment

Penn West Energy Trust is committed to minimizing the environmental impacts from oil and natural gas operations, to practising resource conservation and to involving stakeholders throughout the exploration, development, production and abandonment/reclamation processes. The Trust's continuing policy is to meet or exceed provincial and federal laws, regulations and standards pertaining to the environment. The philosophy of the Trust is to retire approximately 10-15 percent of its opening asset retirement obligations annually, using cash flow. Due to the extent of its environmental programs, the Trust believes little or no benefit would result from the initiation of a reclamation fund.

Penn West's Environmental Policy and Environmental Management Plan covers air, water, soil and waste issues associated with industry operations. The Trust's Environmental Operation Guidelines are used to train Penn West's employees in the Environmental Management Plan's implementation.

The Trust operates long-term liability management programs such as well and facility abandonment, remediation, and reclamation. Penn West evaluates inactive wellbores and facilities to determine whether they can be economically reactivated or should be abandoned and reclaimed. Penn West's liability management programs include auditing of field facilities such as oil batteries, compressor stations and natural gas processing plants. In evaluating producing assets for possible acquisition, Penn West performs due diligence related to environmental performance and regulatory compliance.

In 2005, Penn West maintained Gold Level Status (the highest) in the Canadian GHG Challenge Registry, a cooperative effort by industry, government and environmental organizations to identify and reduce emissions of greenhouse gases such as carbon dioxide. The Trust was a Platinum Level (the highest) participant in the Environment, Health and Safety Stewardship Program initiated by the Canadian Association of Petroleum Producers (CAPP).

Penn West in the Community

As a significant employer and a large business enterprise with activities in numerous communities in Alberta, Saskatchewan and northeast British Columbia, Penn West believes in supporting causes and activities that enhance the communities in which the Trust operates. Penn West financially supports selected charities and causes, and supports employees who individually contribute their time and energy to community causes and activities.

The Trust's approach is to develop active partnerships with charitable and community organizations. We focus in particular on post-secondary education, health care and wellness, and community-oriented organizations.

Penn West's Community Outreach Committee meets monthly to discuss funding proposals.

Over the past five years, Penn West's employees have donated more than 500 pints of blood to Canadian Blood Services in Calgary.

This program has been highly popular among Penn West's employees since its inception in 2001. Our initial involvement came about through Penn West's participation in the Calgary Corporate Challenge Games, a charitable fundraising event that is also one of North America's biggest amateur sporting events. A blood donor challenge is part of the Games.

Penn West subsequently became involved in the Life Link Program (Alberta) (soon to be renamed Partners for Life). Under this program, Penn West pledges units to help meet the need for blood and blood products. The blood donor program has grown to the point where today, the Trust sends a 12-passenger busload of employees from all levels every month to give blood.

During the past six years, a group of Penn West volunteers has helped serve hot lunches for the homeless at Christmas. Other employee volunteers help sort through donations, wrap gifts and make care packages.



Penn West volunteers serving hot lunches for the homeless

Operations Statistical Review

Undeveloped Land

As at December 31,	2005	2004	% Change
Gross acres (000)	4,390	6,058	(28)
Net acres (000)	4,142	5,767	(28)
Average working interest	94%	95%	(1)

Drilling Program

	Three months ended December 31				Years ended December 31			
	2005		2004		2005		2004	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Natural gas	13	13	29	27	150	148	209	197
Oil	37	34	40	38	119	110	195	188
Dry	4	4	5	5	18	18	35	32
Total wells	54	51	74	70	287	276	439	417
Success rate	92%		93%		93%		92%	

Farm-out Activity

Years ended December 31,	2005	2004
Wells drilled on farm-out lands ⁽¹⁾	103	34

⁽¹⁾ Wells drilled on Penn West lands, including recompletions and re-entries, by independent operators pursuant to farm-out agreements.

Activities By Core Area

Core Area	Undeveloped Land as at December 31, 2005 (thousands of net acres)	Net Wells Drilled for the Year ended December 31, 2005
Northern	1,888	44
Central	848	50
Plains	1,406	182
	4,142	276

Reserve Estimates

GLJ Petroleum Consultants Ltd. evaluated Penn West's reserves for all properties. The reserve estimates have been calculated in compliance with the National Instrument 51-101 Standards of Disclosure (NI 51-101). Under NI 51-101, proved reserve estimates are defined as having a high degree of certainty with a targeted 90 percent probability that actual reserves recovered over time will equal or exceed proved reserve estimates. For proved plus probable reserves under NI 51-101, the targeted probability is an equal (50 percent) likelihood that the actual reserves to be recovered will be less than or greater than the proved plus probable reserves estimate.

Proved undeveloped reserves are mainly associated with planned infill drilling in existing pools. No reserves have been booked for coalbed methane or for CO₂ miscible flooding in the Pembina area.

Additional reserve disclosure tables, as required under NI 51-101, are contained in the Trust's Annual Information Form filed on SEDAR at www.sedar.com.

Reserve Estimates by Category

(Forecast Prices and Costs)

Reserve Estimates Category ⁽¹⁾⁽²⁾	Light and Medium Oil (mmbbls)	Heavy Oil (mmbbls)	Natural Gas (bcf)	Natural Gas Liquids (mmbbls)
Proved				
Developed producing	109	43	486	12
Developed non-producing	3	2	35	1
Undeveloped	21	5	44	1
Total proved	132	50	565	14
Probable	28	13	133	3
Total proved plus probable	161	63	698	17

⁽¹⁾ Working interest reserves before royalty burdens and excluding royalty interests.

⁽²⁾ Columns may not add due to rounding.

Reconciliation of Gross Interest Reserves

(Working Interest Before Royalty Burdens and Excluding Royalty Interests) (Forecast Prices and Costs)

Reconciliation Items ⁽¹⁾	Oil and Liquids			Natural Gas			Barrels of Oil Equivalent		
	Proved (mmbbls)	Probable (mmbbls)	Proved Plus Probable (mmbbls)	Proved (bcf)	Probable (bcf)	Proved Plus Probable (bcf)	Proved (mmboe)	Probable (mmboe)	Proved Plus Probable (mmboe)
December 31, 2004	202.3	37.4	239.7	637.0	123.7	760.7	308.5	57.9	366.4
Extensions	3.8	1.1	4.8	31.4	11.2	42.6	9.0	2.9	11.9
Improved recovery	4.3	1.6	5.9	7.5	0.3	7.9	5.5	1.7	7.2
Technical and economic factors	1.0	2.3	3.3	(11.4)	(4.4)	(15.8)	(0.9)	1.6	0.7
Discoveries	0.1	—	0.1	10.9	3.1	14.0	1.9	0.6	2.4
Acquisitions	4.0	2.1	6.1	6.3	2.0	8.3	5.0	2.4	7.5
Dispositions	(0.4)	(0.1)	(0.4)	(13.4)	(2.7)	(16.1)	(2.6)	(0.5)	(3.1)
Production	(18.7)	—	(18.7)	(103.3)	—	(103.3)	(35.9)	—	(35.9)
December 31, 2005	196.3	44.4	240.7	565.1	133.2	698.4	290.5	66.7	357.1

⁽¹⁾ Columns may not add due to rounding.

Reconciliation of Net Interest Reserves

(Working Interest After Royalty Burdens and Including Royalty Interests) (Forecast Prices and Costs)

Reconciliation Items ⁽¹⁾	Oil and Liquids			Natural Gas			Barrels of Oil Equivalent		
	Proved (mmbbls)	Probable (mmbbls)	Proved Plus Probable (mmbbls)	Proved (bcf)	Probable (bcf)	Proved Plus Probable (bcf)	Proved (mmboe)	Probable (mmboe)	Proved Plus Probable (mmboe)
December 31, 2004	182.1	32.8	214.9	520.2	101.1	621.3	268.8	49.7	318.5
Extensions	3.3	0.9	4.2	24.7	9.1	33.8	7.4	2.5	9.9
Improved recovery	4.0	1.6	5.6	5.8	0.3	6.2	4.9	1.7	6.6
Technical and economic factors	0.5	2.2	2.7	(11.9)	(2.7)	(14.6)	(1.5)	1.8	0.3
Discoveries	—	—	—	9.3	2.5	11.9	1.6	0.4	2.0
Acquisitions	3.5	1.8	5.4	5.0	1.5	6.5	4.4	2.1	6.5
Dispositions	(0.3)	—	(0.4)	(10.2)	(2.1)	(12.3)	(2.0)	(0.4)	(2.4)
Production	(16.0)	—	(16.0)	(80.1)	—	(80.1)	(29.4)	—	(29.4)
December 31, 2005	177.1	39.4	216.5	462.8	109.8	572.6	254.2	57.7	312.0

⁽¹⁾ Columns may not add due to rounding.

Proved plus probable reserves of 357 mmboe at the end of 2005 were 3 percent lower than proved plus probable reserves of 366 mmboe at the end of 2004. Total gross proved plus probable reserves, plus royalty interests, were 360 mmboe as at December 31, 2005 (2004 – 370 mmboe).

Net Present Value of Future Net Revenue

Net present values are net of producing wellbore abandonment liabilities and are based on the price assumptions that are contained in the following table. The estimated future net revenues do not represent fair market value.

(Forecast Prices and Costs) (\$ millions)	Net Present Value of Future Net Revenue Before Income Taxes (Discounted)		
Reserve Category ⁽¹⁾	5%	10%	15%
Proved			
Developed producing	\$ 4,614	\$ 3,702	\$ 3,164
Developed non-producing	205	161	133
Undeveloped	454	276	180
Total proved	\$ 5,273	\$ 4,138	\$ 3,477
Probable	995	645	473
Total proved plus probable	\$ 6,267	\$ 4,784	\$ 3,950

⁽¹⁾ Columns may not add due to rounding.

Summary of Pricing and Inflation Rate History and Assumptions as of December 31, 2005

(Forecast Prices and Costs)

Year	Crude Oil				Natural Gas AECO (\$CAD/mcf)	Edmonton Propane (\$CAD/bbl)	Annual Inflation Rate (%)	Exchange Rate (CAD/USD)
	WTI Cushing, Oklahoma (\$US/bbl)	Edmonton Par Price 40° API (\$CAD/bbl)	Hardisty Heavy 12° API (\$CAD/bbl)	Cromer Medium 29° API (\$CAD/bbl)				
Historical								
2001	25.97	39.40	16.94	31.56	6.21	31.85	2.6	0.646
2002	26.08	40.33	26.57	35.48	4.04	21.39	2.2	0.637
2003	31.07	43.66	26.26	37.55	6.66	32.14	2.8	0.721
2004	41.38	52.96	29.11	45.75	6.88	34.70	1.8	0.768
2005	56.60	69.11	34.14	57.07	8.58	42.55	2.2	0.825
Forecast								
2006	57.00	66.25	33.25	55.75	10.60	42.50	2.0	0.850
2007	55.00	64.00	32.75	55.25	9.25	41.00	2.0	0.850
2008	51.00	59.25	32.50	51.25	8.00	38.00	2.0	0.850
2009	48.00	55.75	32.00	48.25	7.50	35.75	2.0	0.850
2010	46.50	54.00	32.00	46.75	7.20	34.50	2.0	0.850
2011	45.00	52.25	33.50	45.25	6.90	33.50	2.0	0.850
2012	45.00	52.25	33.50	45.25	6.90	33.50	2.0	0.850
2013	46.00	53.25	34.00	46.00	7.05	34.00	2.0	0.850
2014	46.75	54.25	34.75	47.00	7.20	34.75	2.0	0.850
2015	47.75	55.50	35.25	48.00	7.40	35.50	2.0	0.850
2016	48.75	56.50	36.00	48.75	7.55	36.25	2.0	0.850
Thereafter	+2%	+2%	+2%	+2%	+2%	+2%	2.0	0.850

Future Development Costs

(Forecast Prices and Costs) (\$ millions)

Year	Proved Future Development Costs
2006	\$ 140
2007	59
2008	57
2009	38
2010	29
2011 and subsequent	90
Undiscounted total	\$ 413
Discounted @ 10%/yr	\$ 307

Management's Discussion and Analysis

Management's discussion and analysis (MD&A) of financial conditions and results of operations should be read in conjunction with the audited consolidated financial statements and accompanying notes of Penn West Energy Trust (the Trust) for the year ended December 31, 2005. Penn West Petroleum Ltd. (Penn West) converted to an income trust on May 31, 2005, and to facilitate meaningful comparisons, the financial results of the Trust are presented on a continuity of interest basis as if it historically carried on the business of Penn West. The date of this MD&A is February 27, 2006. For additional information, including the Trust's audited financial statements and Annual Information Form (when filed), go to the Trust's website at www.pennwest.com or SEDAR at www.sedar.com.

References to cash flow, cash flow per unit-basic, cash flow per unit-diluted, and netbacks included in this MD&A are considered non-generally accepted accounting principles (GAAP) measures and may not be comparable to similar measures provided by other issuers. Management utilizes cash flow and netbacks to assess financial performance and the capacity of the Trust to fund distributions to unitholders and future capital projects. The reconciliation of cash flow to cash flow from operating activities is as follows:

Calculation of Cash Flow (\$ millions, except per unit amounts)

	Three months ended December 31		Years ended December 31	
	2005	2004	2005	2004
Cash flow from operating activities	\$ 368.7	\$ 206.2	\$ 932.8	\$ 816.8
Increase (decrease) in non-cash working capital	(42.4)	10.0	1.8	(23.7)
Payments for surrendered options	—	5.2	141.6	15.6
Environmental expenditures	6.3	16.4	22.6	29.5
Realized foreign exchange gains	—	—	85.8	28.5
Cash flow	\$ 332.6	\$ 237.8	\$ 1,184.6	\$ 866.7
Basic, per unit	\$ 2.03	\$ 1.47	\$ 7.28	\$ 5.37
Diluted, per unit	\$ 2.03	\$ 1.44	\$ 7.14	\$ 5.28

Notes to Reader

This document contains forward-looking statements (forecasts) under applicable securities laws. Forward-looking statements are necessarily based upon assumptions and judgements with respect to the future including, but not limited to, the outlook for commodity prices and capital markets, the performance of producing wells and reservoirs, and the regulatory and legal environment. For a discussion of other factors, please refer to "Notice Regarding Forward-Looking Statements" later in this MD&A. Many of these factors can be difficult to predict. As a result, the forward-looking statements are subject to known or unknown risks and uncertainties that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements. The Trust assumes no responsibility to publicly update or revise any forward-looking statements.

All dollar amounts contained in this document are expressed in millions of Canadian dollars unless noted otherwise.

The calculations of barrels of oil equivalent (boe) are based on a conversion ratio of six thousand cubic feet of natural gas to one barrel of crude oil. This could be misleading if used in isolation, as it is based on energy equivalency at the burner tip and might not represent a value equivalency at the wellhead.

Quarterly Financial Summary (\$ millions, except per unit and production amounts)

Three months ended	2005				2004			
	Dec. 31	Sept. 30	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31
Gross revenues	\$ 554.5	\$ 535.0	\$ 424.2	\$ 405.3	\$ 400.5	\$ 384.3	\$ 390.4	\$ 346.1
Cash flow	\$ 332.6	\$ 334.9	\$ 257.0	\$ 260.1	\$ 237.8	\$ 236.5	\$ 211.2	\$ 181.2
Basic per unit ⁽¹⁾	2.03	2.06	1.58	1.61	1.47	1.46	1.31	1.13
Diluted per unit ⁽¹⁾	2.03	2.04	1.49	1.58	1.44	1.44	1.29	1.11
Net income	\$ 241.1	\$ 209.5	\$ 59.7 ⁽²⁾	\$ 66.9	\$ 68.6	\$ 76.7	\$ 65.5	\$ 61.0
Basic per unit ⁽¹⁾	1.48	1.29	0.37	0.41	0.42	0.48	0.41	0.38
Diluted per unit ⁽¹⁾	1.46	1.27	0.34	0.41	0.42	0.47	0.40	0.37
Distributions declared	\$ 151.8	\$ 127.3	\$ 42.4	\$ —	\$ —	\$ —	\$ —	\$ —
Distributions per unit ⁽¹⁾	0.93	0.78	0.26	—	—	—	—	—
Dividends declared	\$ —	\$ —	\$ —	\$ 10.8	\$ 6.7	\$ 6.7	\$ 6.7	\$ 6.7
Dividends per unit ⁽¹⁾	—	—	—	0.07	0.04	0.04	0.04	0.04
Production								
Liquids (bbls/d)	51,953	51,634	50,633	53,162	53,781	52,966	54,316	51,245
Natural gas (mmcf/d)	277.5	289.0	295.7	289.1	307.4	316.0	329.8	312.0
Total (boe/d)	98,205	99,802	99,910	101,343	105,007	105,639	109,280	103,237

⁽¹⁾ Per unit figures for the periods prior to June 30, 2005 have been restated to reflect the conversion of Penn West common shares to trust units using an exchange ratio of three trust units per share pursuant to the Plan of Arrangement.

⁽²⁾ Net income in the second quarter of 2005 contained stock-based compensation charges related to the trust conversion and current income tax provisions related to the pre-conversion period. Higher commodity prices and lower tax provisions, due to income allocations to the Trust, are reflected in the third and fourth quarter of 2005 net income amounts.

Business Environment

Increased demand for commodities from growing economies such as China, political instability in parts of the world and the occurrence of natural disasters resulted in strong energy prices in 2005. The price of West Texas Intermediate (WTI), a benchmark for light crude oil, averaged US\$56.70 per barrel in 2005, up by 37 percent from 2004.

Heavy oil differentials increased in 2005 as a significant portion of 2005 incremental supply, especially from the Organization of Petroleum Exporting Countries, was heavy oil and there was a continuing shortage of upgrading capacity. The average heavy to light crude oil differential was \$24.16 per barrel in 2005, an increase of 58 percent from \$15.32 per barrel in 2004.

AECO natural gas prices continued to be strong in 2005, increasing by 34 percent to \$8.81 per mcf from \$6.59 per mcf in 2004. Concerns about overall North American supply/demand balance and interruptions in supply from the Gulf of Mexico were the main contributors to this price level.

The benefit of the strength in commodity prices was partially offset by the strength of the Canadian dollar relative to the U.S. dollar and wider heavy oil differentials. Oil marketing contracts are generally based on WTI prices denominated in U.S. dollars; therefore the strengthening Canadian dollar reduces realized prices for Canadian producers. The average exchange rate increased from \$0.769 CAD/USD in 2004 to \$0.825 CAD/USD in 2005. Strong commodity prices increased operating costs due to increases in the demand for energy, steel, services and other costs.

Penn West Strategy

Penn West has proven management, dedicated employees and a business plan appropriate for an energy trust. In terms of production, cash flow, reserves and market capitalization, Penn West progressed from a very small explorer and producer in 1992 to the top ranks of independent oil and natural gas producers in Western Canada. In 2005, Penn West converted into the largest conventional oil and natural gas trust by production in Canada. We believe we have a disciplined approach to business that stresses cost control and product balance. Using this discipline, we have shown the ability not only to explore for and develop reserves, but also to acquire and optimize producing fields. We have a diverse asset base in the Western Canada Sedimentary Basin divided into three core areas, ranging from southern Saskatchewan to regions bordering the Northwest Territories. Our goal is to create and protect unitholder value by:

- > Pursuing an active program of internal development, focusing on low-risk opportunities to maintain production or reduce operating costs, and on resource plays such as our CO₂ enhanced oil recovery project at Pembina and our Seal conventional oil sands project;
- > Participating in exploration, without the requirement to fund capital expenditures, through the farm-out of undeveloped lands;
- > Rationalizing our asset base with the aim of maintaining distributions over the long-term, including asset acquisitions and dispositions that are accretive or strategic; and
- > Maintaining a strong balance sheet.

Using our established business plan, we achieved record cash flow and net income in 2005.

Unitholder Value Measures

Years ended December 31,	2005	2004	2003
Cash flow per unit (\$)	7.28	5.37	5.04
Distributions per unit (\$)	1.97	—	—
Dividends per unit (\$)	0.07	0.16	0.54
Ratio of year-end bank debt to annual cash flow	0.5	0.6	0.5

The Trust has an extensive base of undeveloped land (4.1 million net acres at December 31, 2005) and a strong balance sheet. These attributes, plus strong in-house professional and technical staff, give us the ability to pursue a strategy of both organic growth and optimization through acquisitions, dispositions and farm-out of undeveloped land. We believe that the application of financial discipline is also a key factor in achieving superior returns on investment for our unitholders.

Performance Indicators

Years ended December 31,	2005	2004	2003
Return on capital employed	36.2%	8.4%	15.9%
Total assets (\$ millions)	3,967	3,867	3,310
Return on equity	28.3%	15.3%	30.1%

Cash Flow and Net Income

A 57 percent increase in Q4 2005 operating netbacks resulted in a 40 percent increase in cash flow and a 251 percent increase in net income from Q4 2004. Operating netbacks were higher mainly due to increased prices received for crude oil and natural gas. Prices received for crude oil and NGL are related to world markets and the quality of crude oil produced. The Trust's liquids production

is 64 percent light oil and NGL that receives prices close to Edmonton par price. This benchmark price increased by more than 24 percent in Q4 2005 from Q4 2004.

Natural gas prices in North America are more significantly impacted by regional supply and demand factors. The geographic constraints can result in volatility due to the supply and demand imbalances that occur from time to time. Benchmark AECO prices for natural gas were 73 percent higher in the current quarter than in Q4 2004.

Cash flow and net income before taxes in 2005 increased mainly due to the increases in the sales prices of crude oil and natural gas. The impact of higher prices during 2005 was partially offset by a reduction in pre-tax income of \$53 million to reflect the payout of outstanding stock options in accordance with the Plan of Arrangement in respect of the trust conversion and the terms of the stock option plan. After-tax net income was further impacted by future income tax recoveries in the period since converting to a trust.

Production and Netbacks

	Three months ended December 31			Years ended December 31		
	2005	2004	% Change	2005	2004	% Change
Natural gas: mmcf per day	277.5	307.4	(10)	287.8	316.3	(9)
Operating netback (\$ per mcf):						
Sales price	\$ 11.66	\$ 6.81	71	\$ 8.68	\$ 6.68	30
Hedging gain	—	0.02	—	0.06	—	—
Royalties	(2.67)	(1.51)	77	(1.86)	(1.43)	30
Operating costs	(0.87)	(0.71)	23	(0.85)	(0.69)	23
Netback	\$ 8.12	\$ 4.61	76	\$ 6.03	\$ 4.56	32
Light oil and NGL: bbls per day	33,227	34,524	(4)	33,137	34,943	(5)
Operating netback (\$ per bbl):						
Sales price	\$ 64.28	\$ 52.67	22	\$ 62.59	\$ 48.09	30
Hedging loss	—	(4.10)	—	—	(6.05)	—
Royalties	(11.46)	(9.47)	21	(10.17)	(7.86)	29
Operating costs	(15.17)	(13.14)	15	(14.43)	(12.80)	13
Netback	\$ 37.65	\$ 25.96	45	\$ 37.99	\$ 21.38	78
Conventional heavy oil: bbls per day	18,726	19,257	(3)	18,705	18,136	3
Operating netback (\$ per bbl):						
Sales price	\$ 34.95	\$ 29.89	17	\$ 35.71	\$ 31.73	13
Royalties	(5.67)	(4.42)	28	(5.41)	(4.62)	17
Operating costs	(9.64)	(8.32)	16	(9.30)	(8.49)	10
Netback	\$ 19.64	\$ 17.15	15	\$ 21.00	\$ 18.62	13
Total liquids: bbls per day	51,953	53,781	(3)	51,842	53,079	(2)
Operating netback (\$ per bbl):						
Sales price	\$ 53.71	\$ 44.51	21	\$ 52.89	\$ 42.50	24
Hedging loss	—	(2.63)	—	—	(3.98)	—
Royalties	(9.38)	(7.67)	22	(8.45)	(6.75)	25
Operating costs	(13.18)	(11.41)	16	(12.58)	(11.33)	11
Netback	\$ 31.15	\$ 22.80	37	\$ 31.86	\$ 20.44	56

Production and Netbacks (CONTINUED)

	Three months ended December 31			Years ended December 31		
	2005	2004	% Change	2005	2004	% Change
Combined totals: boe⁽¹⁾						
Daily production	98,205	105,007	(6)	99,807	105,788	(6)
Operating netback (\$ per boe):						
Sales price	\$ 61.38	\$ 42.73	44	\$ 52.50	\$ 41.27	27
Hedging gain (loss)	—	(1.28)	—	0.18	(1.98)	—
Royalties	(12.52)	(8.33)	50	(9.74)	(7.65)	27
Operating costs	(9.44)	(7.94)	19	(8.99)	(7.75)	16
Netback	\$ 39.42	\$ 25.18	57	\$ 33.95	\$ 23.89	42

⁽¹⁾ Barrels of oil equivalent (boe) are based on six mcf of natural gas equals one barrel of oil (6:1).

Production of 98,205 boe per day in the fourth quarter of 2005 was down slightly from the third quarter of 2005 due to minor asset dispositions. Production levels in 2005 were impacted by wet weather that limited access and product hauling. Unanticipated production interruptions, normal production declines and a 47 percent reduction in capital spending also impacted 2005 production levels compared to 2004.

For the year ended December 31, 2005, the Trust received an average light oil and liquids netback of \$37.99 per barrel, an average conventional heavy oil netback of \$21.00 per barrel, and an average natural gas netback of \$6.03 per mcf. The light oil and liquids netback was up by 78 percent from \$21.38 per barrel for the year ended December 31, 2004 due to higher average commodity prices in 2005 and a 2004 hedging loss of \$6.05 per barrel, compared to no realized gain or loss in 2005. The increase was partially offset by higher royalties and operating expenses experienced in 2005. The heavy oil netback was up by 13 percent from \$18.62 per barrel in 2004 mainly due to higher benchmark oil prices, partially offset by the larger light/heavy oil price differential and higher royalties and operating costs. The natural gas netback was up by 32 percent from \$4.56 per mcf in 2004 due to higher prices, partially offset by higher royalties and operating expenses in 2005.

In Q4 2005, the Trust achieved an overall netback of \$39.42 per boe, consisting of a light oil and liquids netback of \$37.65 per barrel, a conventional heavy oil netback of \$19.64 per barrel, and a natural gas netback of \$8.12 per mcf. All products contributed to the 57 percent overall increase from \$25.18 per boe in 2004. The Q4 2005 light oil and liquids netback increased by 45 percent from \$25.96 per barrel in Q4 2004, the netback for conventional heavy oil increased by 15 percent from \$17.15 per barrel in Q4 2004, and the natural gas netback increased by 76 percent from \$4.61 per mcf in Q4 2004. The increased netbacks in the quarter were the result of higher commodity prices in Q4 2005 and hedging losses in the 2004 period, partially offset by increased royalties and increased operating expenses.

Oil and Natural Gas Revenues

Years ended December 31, (\$ millions)	2005	2004	2003
Light oil and natural gas liquids	\$ 757.0	\$ 537.7	\$ 497.3
Conventional heavy oil	243.8	210.6	113.7
Total liquids	1,000.8	748.3	611.0
Natural gas	918.2	773.0	783.2
Total	\$ 1,919.0	\$ 1,521.3	\$ 1,394.2

Increases (Decreases) in Gross Revenues, before Royalties

(\$ millions)		
Gross revenues – 2004		\$ 1,521.3
Decrease in light oil and NGL production		(29.2)
Increase in light oil and NGL prices		248.5
Increase in conventional heavy oil production		6.0
Increase in conventional heavy oil prices		27.2
Decrease in natural gas production		(71.5)
Increase in natural gas prices		216.7
Gross revenues – 2005		\$ 1,919.0

Oil Revenues and Marketing

The Trust's overall quality of crude oil remained high, averaging 28 degrees API in 2005. Light and medium oil and NGL made up 33 percent of the Trust's total production, with an average quality of 37 degrees API. Conventional heavy oil, at an average of 15 degrees API, accounted for 19 percent of the Trust's production. The Trust's light and heavy oil netbacks remained strong throughout 2005 despite larger differentials between light and heavy oil prices. Most of the Trust's production is sold at the field level to various refiners and marketing companies.

Revenues from light oil and liquids increased by 41 percent to \$757 million for the year ended December 31, 2005 from \$538 million in 2004. This increase was attributable to higher average prices in 2005. The Trust's average light oil and liquids price increased by 30 percent to \$62.59 per barrel for the year ended December 31, 2005 from \$48.09 per barrel in 2004. The average daily production of light oil and liquids decreased by 5 percent to 33,137 barrels per day in 2005 from 34,943 barrels per day in 2004. Hedging reduced the net price received in 2004 by \$6.05 to \$42.04 per barrel. At December 31, 2005, the Trust had hedged 20,000 barrels per day for 2006 using collars with a floor price of US\$47.50/bbl and a ceiling price of US\$67.86/bbl. The Trust maintains an active hedging program.

Light oil and NGL revenues in the fourth quarter of 2005 were \$197 million, an increase of 28 percent from Q4 2004 revenues of \$154 million. This increase was due to significantly higher average prices in the 2005 quarter. The Trust's average light oil and NGL price for Q4 2005 was \$64.28 per barrel, an increase of 22 percent over the Q4 2004 average price of \$52.67 per barrel. Hedging reduced the net price received in Q4 2004 by \$4.10 to \$48.57 per barrel. Production of 33,227 barrels per day of light oil and NGL was down by 4 percent from production of 34,524 barrels per day in Q4 of 2004.

Revenues from conventional heavy oil for the year ended December 31, 2005 increased by 16 percent to \$244 million from \$211 million in 2004. This increase was attributable to higher average prices in the year. The Trust's average conventional heavy oil price increased by 13 percent to \$35.71 per barrel in 2005 from \$31.73 in 2004, and the average production of conventional heavy oil increased by 3 percent to 18,705 barrels per day in 2005 from 18,136 barrels per day in 2004.

In the fourth quarter of 2005, conventional heavy oil revenues increased by 13 percent to \$60 million from \$53 million in Q4 2004. This increase was also due to higher average prices in the quarter. Conventional heavy oil prices were \$34.95 per barrel in Q4 2005, an increase of 17 percent from Q4 2004 prices of \$29.89 per barrel. Production in Q4 was down by 3 percent to 18,726 barrels per day in 2005 from 19,257 barrels per day in 2004.

Natural Gas Revenues and Marketing

The Trust maintained significant weighting to the Alberta natural gas market in 2005, as this market continued to offer a premium netback relative to other indices. At December 31, 2005, the Trust marketed approximately 89 percent of its natural gas sales directly, with the remaining 11 percent marketed by aggregators.

For the year ended December 31, 2005, Penn West received an average natural gas sales price of \$8.68 per mcf, an increase of 30 percent from \$6.68 per mcf in 2004. Revenues from natural gas increased by 19 percent in the year ended December 31, 2005 to \$918 million from \$773 million in 2004. The increased revenue in 2005 over 2004 was due to pricing, as natural gas production of 288 mmcf per day in 2005 was 9 percent less than production of 316 mmcf per day in 2004. The decrease in natural gas production in 2005 was attributable to minor asset dispositions, natural reservoir declines and a reduced capital program.

Natural gas revenues in the fourth quarter of 2005 increased by 54 percent to \$298 million from \$193 million in the same period in 2004. This was the result of higher natural gas prices partially offset by lower production volumes in Q4 2005. Natural gas prices of \$11.66 per mcf in Q4 2005 were 71 percent higher than Q4 2004 prices of \$6.81 per mcf, and natural gas production of 278 mmcf per day in Q4 2005 was 10 percent lower than the 307 mmcf per day in Q4 2004.

The Trust makes use of financial instruments at various times in the commodity price cycle to manage downside risk. On average, the Trust hedged approximately 20 percent of its natural gas production in 2005. For the year ended December 31, 2005, natural gas hedging increased the sales price received by \$0.06 per mcf, and had no impact in 2004. The Trust currently has a number of AECO collars in place for 2006. For details on financial instruments outstanding at December 31, 2005, see note 10 to the audited consolidated financial statements.

Royalty Expenses

Years ended December 31,	2005	2004	2003
Royalties, net of Alberta			
Royalty Tax Credit (\$ millions)	\$ 355.0	\$ 296.1	\$ 265.1
Average rate (\$/boe)	\$ 9.74	\$ 7.65	\$ 7.15
Percentage of gross revenues	19%	20%	19%

The average royalty rate incurred for the year ended December 31, 2005 was 19 percent compared to 20 percent for the same period in 2004. The royalty rate comprises an oil and liquids royalty rate of 16 percent compared to 18 percent in 2004 and a natural gas royalty rate of 21 percent in both 2005 and 2004. The decrease in the oil and liquids royalty rate was mainly attributable to hedging losses in 2004. The year-to-year royalty rates also vary with commodity prices and the proportion of oil production relative to natural gas production.

For the fourth quarters of 2005 and 2004, the average royalty rate incurred was 20 percent. The oil and liquids royalty component was 18 percent in Q4 of 2005 and Q4 2004. The natural gas royalty was 23 percent in Q4 2005 compared to 22 percent in Q4 2004.

Operating Expenses

Years ended December 31,	2005	2004	2003
Operating expenses (\$ millions)	\$ 327.4	\$ 300.4	\$ 245.6
Average cost (\$/boe)	\$ 8.99	\$ 7.75	\$ 6.63
Percentage of gross revenues	17%	20%	18%

For the year ended December 31, 2005, operating costs averaged \$8.99 per boe of production, a 16 percent increase from the average cost of \$7.75 per boe in 2004. The production decline during 2005 accounted for 10 percent of the increase in unit operating costs. In addition, operating costs are higher for oil properties, and in 2005 liquids production increased to 52 percent of total production from 50 percent in 2004. A significant portion of the Trust's liquids production is light oil that commands a premium price; therefore, the Trust is well positioned to absorb operating cost increases and maintain economic operating netbacks. Operating costs were impacted by higher energy and fuel costs, planned facility maintenance projects, increased natural gas compression costs and lower natural gas production. Higher industry activity and commodity prices also impacted operating costs by increasing the demand for services, thus increasing input costs resulting in higher rates charged by our service providers.

Light oil and liquids operating costs increased by 13 percent to \$14.43 per barrel in the year ended December 31, 2005 from \$12.80 per barrel in 2004. Operating costs for conventional heavy oil increased by 10 percent to \$9.30 per barrel during 2005 from \$8.49 per barrel in 2004. Operating costs for natural gas averaged \$0.85 per mcf in 2005, an increase of 23 percent from \$0.69 per mcf in 2004.

Q4 2005 operating costs averaged \$9.44 per boe, 19 percent higher than Q4 2004 operating costs of \$7.94 per boe. This increase was the result of the higher liquids production as a percentage of total production, higher energy and fuel costs, increased industry demand for oilfield services, and lower total production in the 2005 quarter. The overall production decline from Q4 2004 to Q4 2005 accounted for 13 percent of the increase in unit operating costs.

Light oil and liquids operating costs in Q4 2005 increased by 15 percent to \$15.17 per barrel from \$13.14 per barrel in Q4 2004, and natural gas operating costs increased by 23 percent to \$0.87 per mcf in Q4 2005 from \$0.71 per mcf in Q4 2004.

General and Administrative Expenses

Years ended December 31,	2005	2004	2003
Gross expenses (\$ millions)	\$ 45.0	\$ 41.3	\$ 34.0
Operator recoveries (\$ millions)	(21.9)	(25.2)	(21.5)
Net expenses (\$ millions)	\$ 23.1	\$ 16.1	\$ 12.5
Gross general and administrative expenses – average cost (\$/boe)	\$ 1.24	\$ 1.07	\$ 0.92
Percentage of gross revenues	2%	3%	2%
Net general and administrative expenses – average cost (\$/boe)	\$ 0.64	\$ 0.42	\$ 0.34
Percentage of gross revenues	1%	1%	1%

Gross general and administrative expenses increased due to higher compensation costs to retain staff. On a unit of production basis, the gross general and administrative costs increased by 16 percent to \$1.24 per boe for the year ended December 31, 2005 from \$1.07 per boe in 2004. Net general and administrative expenses on a per unit basis increased by 52 percent to \$0.64 per boe in 2005 from \$0.42 per boe in 2004. The reduction in operator recoveries resulted from the planned reduction in capital spending due to the trust conversion. Q4 2005 net general and administrative expenses were up by 36 percent on a per unit basis to \$0.75 per boe from \$0.55 per boe in Q4 2004.

Equity-Based Compensation Provision

Years ended December 31,	2005	2004	2003
Unit-based compensation (\$ millions)	\$ 77.2	\$ 84.1	\$ 48.0
Average cost (\$/boe)	\$ 2.12	\$ 2.17	\$ 1.30
Percentage of gross revenues	4%	6%	3%

Upon conversion to a Trust, unvested stock options were vested in accordance with the terms of the stock option plan and the Plan of Arrangement. Option-holders had several alternatives including a cash payment, purchasing Penn West shares at the option exercise price or carrying the option forward. Of the total unit-based compensation charge of \$77 million in 2005, \$53 million represented the cash paid to option-holders in the second quarter of 2005 in excess of the previously recorded stock-based compensation liability. Penn West paid \$81 million at the end of May 2005 to option-holders who elected to receive cash for surrendering stock options that were outstanding at the time of the trust conversion. The impact of these payments was expensed in Q2 2005.

In May 2005, the Trust implemented a unit rights incentive plan. Compensation expense related to this plan is based on the fair value of trust unit rights granted and determined using the Black-Scholes option pricing model. The resulting expense is amortized over the remaining vesting periods on a straight-line basis. Compensation expense of \$6 million relating to the unit rights incentive plan was expensed in the year ended December 31, 2005.

Financing Expenses

Years ended December 31,	2005	2004	2003
Interest (\$ millions)	\$ 23.2	\$ 17.0	\$ 11.9
Cash flow times interest coverage	52.1	51.9	69.5
Average cost (\$/boe)	\$ 0.63	\$ 0.45	\$ 0.32
Percentage of gross revenues	1%	1%	1%

Interest expense for the year ended December 31, 2005 amounted to \$23 million, an increase of 35 percent from \$17 million in 2004. This increase was due to higher 2005 short-term interest rates and average debt levels that resulted from the payment of over \$200 million in income taxes and \$142 million for the surrender of stock options. With 2005 cash flows and the planned capital program reductions, the Trust repaid the majority of this debt prior to the end of 2005.

Q4 2005 interest expense of \$7 million was 75 percent higher than Q4 2004 interest expense of \$4 million as a result of higher average debt levels in the 2005 quarter and higher short-term interest rates.

Capital Expenditures

(\$ millions)	Three months ended December 31		Years ended December 31		
	2005	2004	2005	2004	2003
Property (dispositions) acquisitions, net	\$ (91.3)	\$ 101.4	\$ (5.8)	\$ 332.3	\$ 0.3
Land acquisition and retention	3.7	3.9	13.5	18.4	47.4
Drilling and completions	61.0	89.4	277.1	301.5	349.6
Facilities and well equipping	30.0	27.1	155.2	191.3	191.4
Geological and geophysical	0.8	4.6	7.4	16.3	18.1
Pembina CO ₂ pilot project	1.9	2.3	8.1	4.9	—
Administrative	0.2	0.3	1.2	0.9	1.3
Capital expenditures	\$ 6.3	\$ 229.0	\$ 456.7	\$ 865.6	\$ 608.1

The decrease in 2005 capital expenditures from 2004 reflected planned reductions due to the trust conversion, the February 2004 acquisition of oil and natural gas assets and undeveloped land in southwest Saskatchewan for \$234 million, and \$91 million of net property dispositions in Q4 2005 versus the \$101 million in net acquisitions in Q4 2004.

The Pembina CO₂ pilot project represents capital expenditures, including injectants, for which no reserves have been booked. Capital expenditures exclude the impact of property, plant and equipment adjustments for asset retirement obligations and future income taxes. For details of these adjustments, see notes 3 and 5 to the audited consolidated financial statements.

Depletion, Depreciation and Accretion

Years ended December 31,	2005	2004	2003
Depletion and depreciation (\$ millions)	\$ 416.5	\$ 394.3	\$ 291.9
Accretion (\$ millions)	21.1	18.8	11.8
	\$ 437.6	\$ 413.1	\$ 303.7
Average rate (\$/boe)	\$ 12.01	\$ 10.67	\$ 8.19
Percentage of gross revenues	23%	27%	22%

The increase in the 2005 depletion, depreciation and accretion provision from 2004 reflects a rate increase of 13 percent that was partially offset by lower production. The rate increase was due to a higher portion of the capital program being allocated to infill drilling and other production optimization activities, consistent with the Trust's mandate that focuses on capital efficiency. Generally, a lower amount of reserve additions is assigned to these activities than to conventional exploration and development company activities; however, production is added or maintained at a lower capital cost per flowing barrel of production.

Foreign Exchange

Years ended December 31, (\$ millions)	2005	2004	2003
Foreign exchange loss (gain)	\$ 4.5	\$ (27.7)	\$ (95.6)
Loss (gain) from written Canadian dollar calls	—	(12.7)	12.7
Net foreign exchange loss (gain)	\$ 4.5	\$ (40.4)	\$ (82.9)
Average loss (gain) (\$/boe)	\$ 0.12	\$ (1.04)	\$ (2.24)
Percentage of gross revenues	—	3%	6%

During Q1 2005, the Trust converted US\$205 million of its US-denominated borrowings to Canadian dollars at an average exchange rate of \$0.829 CAD/USD, resulting in a realized foreign exchange gain of \$63 million. In May 2005, the Trust converted its remaining US\$85 million of US-denominated borrowings to Canadian dollars at an average exchange rate of \$0.803 CAD/USD and realized an additional \$23 million foreign exchange gain. As at December 31, 2005, the Trust had no foreign currency-denominated debt versus the \$290 million of US-denominated debt outstanding at December 31, 2004.

Taxes

Years ended December 31,	2005	2004	2003
Current income taxes (\$ millions)	\$ 54.1	\$ 17.8	\$ 9.9
Future income taxes (recovery) (\$ millions)	(1.1)	109.6	97.3
	\$ 53.0	\$ 127.4	\$ 107.2
Effective tax rate	8%	31%	19%
Capital taxes (\$ millions)	\$ 14.7	\$ 10.1	\$ 10.1

In Q4 2005, no current income tax provision was required compared to a recovery of \$13 million in the same period of 2004. The cash income tax provision for 2005 was \$54.1 million compared to \$18 million in the 2004 period due to higher cash flow in 2005. The trust conversion on May 31, 2005 resulted in a short income tax year that accelerated \$214 million of cash income taxes, as a significant amount of Penn West's taxable income was earned in a partnership. Of this amount, \$54 million was expensed as current income taxes to May 31, 2005, \$146 million was reflected as a reduction to the future income tax liability and \$13 million, being the tax rate differential, was recorded as a restructuring charge.

The trust conversion also impacted capital taxes in Q2 2005. Part of the plan of arrangement consisted of the conveyance of properties from a partnership to a corporation. This transaction increased taxable capital for Large Corporations Tax in the corporation for the tax year ended December 31, 2005; however, this increase will not apply in subsequent taxation years.

In Q4 2005, a \$51 million future tax recovery was recorded compared to a \$48 million provision in Q4 2004. There was a future income tax recovery in 2005 of \$1 million compared to a future income tax provision of \$110 million in 2004. The 2005 future income tax provisions reflect future tax reductions related to 2005 income allocations to the Trust and lower tax rates. Interest and royalty payments, by the operating corporation to the Trust, are accounted for as a reduction of accumulated timing differences and accordingly lowers the future income tax provision.

In Q4 2005, a \$28 million general future tax rate reduction was recorded to reflect lower scheduled future tax rates resulting from timing differences, reversing in later taxation years under current legislation. In the third quarter of 2005, a \$3 million tax rate reduction was recorded to reflect British Columbia's 1.5 percent general tax rate reduction. In the first quarter of 2004, a \$20 million future income tax recovery was recorded to reflect the 2004 tax rate reduction enacted by the Government of Alberta.

Tax Pools

As at December 31, (\$ millions)	2005	2004	2003
Undepreciated Capital Cost (UCC)	\$ 519.0	\$ 276.4	\$ 270.1
Cumulative Canadian Oil and Gas Property Expense (COGPE)	707.6	611.5	679.2
Cumulative Canadian Development Expense (CDE)	329.8	95.4	136.6
Cumulative Canadian Exploration Expense (CEE)	—	—	—
Total tax pools	\$ 1,556.4	\$ 983.3	\$ 1,085.9

Items Affecting Cash Flow and Net Income

Years ended December 31,	2005		2004		2003	
	\$/boe	%	\$/boe	%	\$/boe	%
Oil and natural gas revenues	\$ 52.68	100.0	\$ 39.29	100.0	\$ 37.62	100.0
Net royalties	(9.74)	(18.5)	(7.65)	(19.5)	(7.15)	(19.0)
Operating expenses	(8.99)	(17.1)	(7.75)	(19.7)	(6.63)	(17.6)
Transportation	(0.62)	(1.1)	(0.66)	(1.7)	(0.71)	(1.9)
Net operating income	33.33	63.3	23.23	59.1	23.13	61.5
General and administrative expenses	(0.64)	(1.2)	(0.42)	(1.1)	(0.34)	(0.9)
Interest	(0.63)	(1.2)	(0.45)	(1.1)	(0.32)	(0.9)
Realized foreign exchange gain	2.35	4.4	0.74	1.9	—	—
Current and capital taxes	(1.89)	(3.6)	(0.71)	(1.8)	(0.54)	(1.4)
Cash flow	32.52	61.7	22.39	57.0	21.93	58.3
Unrealized foreign exchange gain (loss)	(2.48)	(4.7)	0.30	0.8	2.24	6.0
Unit-based compensation	(2.12)	(4.0)	(2.17)	(5.5)	(1.30)	(3.5)
Risk management activities	(0.09)	(0.2)	—	—	—	—
Depletion, depreciation and accretion	(12.01)	(22.8)	(10.67)	(27.2)	(8.19)	(21.8)
Future income taxes	0.03	—	(2.83)	(7.2)	(2.63)	(7.0)
Net income	\$ 15.85	30.0	\$ 7.02	17.9	\$ 12.05	32.0

Cash flow increased by 37 percent to \$1.2 billion for the year ended December 31, 2005 from \$867 million in 2004. Basic cash flow per unit rose by 36 percent to \$7.28 per unit in 2005 from \$5.37 per unit in 2004.

Q4 2005 cash flow was \$333 million, an increase of 40 percent from \$238 million in Q4 2004. Basic cash flow per unit increased 38 percent to \$2.03 per unit in Q4 2005 from \$1.47 per unit in Q4 2004.

Net income for the year ended December 31, 2005 increased by 112 percent to \$577 million from \$272 million in 2004. Basic net income per unit increased by 111 percent in 2005 to \$3.55 per unit from \$1.68 per unit in 2004.

Net income in Q4 2005 increased by 251 percent to \$241 million from \$69 million in Q4 2004. Basic net income per unit increased by 252 percent to \$1.48 per unit in Q4 2005 from \$0.42 per unit in Q4 2004.

Market Risk Management

The Trust is exposed to normal market risks inherent in the oil and natural gas business, including credit risk, commodity price risk, interest rate risk and foreign currency risk. The Trust, from time to time, attempts to minimize exposure to these risks using financial instruments.

Credit Risk

Credit risk is the risk of loss if purchasers or counterparties do not fulfill their contractual obligations. All of the Trust's receivables are with customers in the oil and natural gas industry and are subject to normal industry credit risk. In order to limit the risk of non-performance of counterparties to derivative instruments, the Trust transacts only with financial institutions with high credit ratings and obtains security in certain circumstances.

Commodity Price Risk

Commodity price risk is the Trust's most significant exposure. Crude oil prices are influenced by worldwide factors such as OPEC actions, supply and demand fundamentals, and political events. Natural gas prices are generally influenced by oil prices and North American natural gas supply and demand factors. Pursuant to policy, the Trust may, from time to time, manage these risks through the use of costless collars or other financial instruments up to a maximum of 50 percent of sales volumes.

The Trust maintains an active hedging program. Other financial instruments include Alberta electricity contracts with positive mark-to-market values. For details of the financial instruments outstanding on December 31, 2005, see note 10 to the audited consolidated financial statements.

Interest Rate Risk

The Trust maintains its debt in floating-rate bank facilities, resulting in exposure to fluctuations in short-term interest rates. From time to time, the Trust may increase the certainty of future interest rates by using financial instruments to swap floating interest rates for fixed rates or to collar interest rates. The Trust had no financial instruments in place at December 31, 2005 that affected its future interest rate exposure.

Foreign Currency Rate Risk

Prices received for sales of crude oil and certain bank loans are referenced to, or denominated in, US dollars. Accordingly, realized oil prices, interest costs and debt levels may be impacted by CAD/USD exchange rates. When considered appropriate, the Trust may use financial instruments to fix or collar future exchange rates. At December 31, 2005 the Trust had no financial instruments outstanding related to foreign exchange rates.

Liquidity and Capital Resources

Capitalization

As at December 31,	2005		2004		2003	
	\$ millions	%	\$ millions	%	\$ millions	%
Trust unit equity, at market	\$ 6,203	90.5	\$ 4,269	86.0	\$ 2,586	81.0
Bank loan	542	7.9	503	10.2	442	13.8
Working capital deficiency ⁽¹⁾	127	1.6	190	3.8	165	5.2
Total enterprise value	\$ 6,872	100.0	\$ 4,962	100.0	\$ 3,193	100.0

⁽¹⁾ Current assets less current liabilities.

Penn West's closing market price on the Toronto Stock Exchange was \$37.99 per unit in 2005. The closing market price in the prior years, after accounting for the conversion ratio of three trust units issued for each common share, was \$26.42 per unit in 2004 and \$16.05 per unit in 2003. Total enterprise value was \$6.9 billion at December 31, 2005 compared to \$5.0 billion at year end 2004.

Dividends of \$18 million paid to shareholders prior to the trust conversion, distributions of \$270 million paid to unitholders after the conversion, and the 2005 capital program were funded using a portion of internally generated 2005 cash flow. Distributions declared subsequent to the trust conversion represented 43 percent of cash flow and 66 percent of net income. The remaining cash flow was used to repay bank debt which, at December 31, 2005, was \$542 million compared to \$503 million at December 31, 2004 after the payment of cash taxes and stock options related to the trust conversion in 2005.

In the second quarter of 2005, the Trust entered into an unsecured, extendible, three-year revolving syndicated credit facility with an aggregate borrowing limit of \$1,170 million plus a \$50 million operating facility. The credit facility contains provision for stamping fees on Bankers' Acceptances and LIBOR loans, and standby fees on lines not drawn depending on certain consolidated bank debt to earnings before interest, taxes and depreciation and depletion (EBITDA) ratios. The Trust is in compliance with all financial covenants relating to the facility.

Under the terms of its trust indenture, the Trust is required to distribute all of its taxable income to unitholders. Distributions may be monthly or special and in cash or in trust units at the discretion of the Board of Directors. To the extent that additional cash distributions are paid and capital programs are not adjusted, debt levels may increase. In the event that a special distribution in the form of trust units is declared, the terms of the Trust Indenture require that the outstanding units be consolidated immediately subsequent to the distribution. The number of outstanding trust units would remain at the number outstanding immediately prior to the distribution of trust units and that portion of the Trust's taxable income would be allocated to the unitholders.

The philosophy of the Trust is to retire approximately 10 percent to 15 percent of its opening asset retirement obligations annually using cash flow. Due to the extent of its environmental programs, the Trust believes little or no benefit would result from the initiation of a reclamation fund. The Trust believes its program is sufficient to meet or exceed existing environmental regulations and best industry practices. In the event of significant changes to the environmental regulations or the cost of environmental activities, a higher portion of cash flow will be required to fund these expenditures.

Reconciliation of Cash Flow to Distributions

(\$ millions, except indicators and per unit amounts)	Three months ended	Seven months ended
	December 31, 2005	December 31, 2005 ⁽¹⁾
Cash flow from operating activities	\$ 368.7	\$ 696.5
(Decrease) increase in non-cash working capital	(42.4)	34.6
Payments for surrendered options	—	0.6
Environmental expenditures	6.3	12.6
Cash flow	\$ 332.6	\$ 744.3
Funding of capital expenditures	(6.3)	(203.3)
Environmental expenditures	(6.3)	(12.6)
Debt repayments	(168.2)	(206.9)
Cash distributions	\$ 151.8	\$ 321.5
Accumulated cash distributions, beginning of period	169.7	—
Accumulated cash distributions, end of period	\$ 321.5	\$ 321.5
Net income	\$ 241.1	\$ 485.6
Cash distributions as a percentage of net income	63%	66%
Cash distributions as a percentage of cash flow	46%	43%
Cash distributions per unit	\$ 0.93	\$ 1.97

⁽¹⁾ Includes the operations of the Trust subsequent to the effective date of the trust conversion, May 31, 2005.

During 2005, Penn West paid dividends of \$18 million (2004 – \$108 million) and the Trust paid distributions of \$270 million. The first monthly cash distribution of the Trust, in the amount of \$42 million or \$0.26 per trust unit, was paid on July 15, 2005 to unitholders of record on June 30, 2005. On October 17, 2005, the Trust announced an increased monthly distribution of \$0.31 per trust unit, a 19 percent increase, that was payable on November 15, 2005 to unitholders of record on October 31, 2005. On February 2, 2006, a further 10 percent or \$0.03 per trust unit monthly distribution increase was announced effective for the February distribution payable March 15, 2006. The distribution increases were made considering expected commodity prices that exceed those initially forecasted, hedging contracts put in place to increase the likelihood of achieving price expectations, strong industry interest in the Trust's undeveloped land base, and the level of projected capital requirements for 2006 and beyond.

The Trust's 2005 distributions, for both Canadian and U.S. unitholders, were 100 percent taxable with no return of capital.

Plan of Arrangement

On May 27, 2005, the shareholders approved the proposed reorganization of Penn West into an income trust as described in the Plan of Arrangement dated April 22, 2005. Court approval was obtained on the effective date of the conversion, May 31, 2005. Penn West shareholders received three units of the Trust for each Penn West share. The Trust commenced operations on May 31, 2005 with a new business mandate and legal structure pursuant to the trust indenture dated April 22, 2005. The Trust assumed all assets and liabilities previously held by Penn West.

Prior to the trust conversion, the audited consolidated financial statements included the accounts of Penn West and its subsidiaries and partnerships. The audited consolidated financial statements of the Trust have been prepared on a continuity of interest basis, as if the Trust historically carried on the business of Penn West, and include the financial results of Penn West to May 31, 2005 and the Trust for the subsequent months. Per unit figures of comparative periods have been restated to reflect the conversion ratio of three units of the Trust for each share of Penn West.

Reorganization costs of \$36 million, pre-tax, relating to financial advisors, legal fees, short-year tax rate differences and additional capital taxes associated with the Plan of Arrangement were charged to accumulated earnings in the second quarter of 2005. In addition, as Penn West's stock option plan contained a cash payment alternative, \$53 million related to canceling outstanding options was expensed in the second quarter of 2005. At the end of May 2005, Penn West made cash payments of \$81 million for the surrender of the remaining vested and unvested stock options pursuant to the Plan of Arrangement and the terms of the stock option plan.

In addition, the Trust conversion resulted in a short income tax year that accelerated \$146 million of cash income taxes, as a significant amount of Penn West's taxable income was earned in a partnership.

Business Risks

The Trust's exploration, development, production and asset acquisition/disposition activities are conducted in the Western Canada Sedimentary Basin and involve a number of business risks. These risks include the uncertainty of replacing annual production and finding new reserves on an economic basis, the potential instability of commodity prices, exchange rates and interest rates, and other factors discussed under "Notice Regarding Forward-Looking Statements."

To the extent practical, the Trust mitigates these risks by employing highly trained and competent management and staff who mitigate these risks by:

- > Balancing the production portfolio between oil and natural gas;
- > Pursuing low risk development and production optimization projects and implementing a phased approach to significant projects such as the Pembina/Swan Hills CO₂ enhanced oil recovery project and the Seal oil sands project;
- > Pursuing strategic acquisitions, dispositions and the farm-out of undeveloped land; and,
- > Maintaining high average capital efficiency and low operating and general and administrative costs.

The Trust's management team believes that these principles, validated through Penn West's 13-year track record of growth and profitability, will continue to apply under the Trust's business model.

The oil and natural gas industry is subject to extensive government influence through taxation policies and environmental legislation. While taxation policy has remained relatively stable, there is always the potential for change.

The industry is also subject to extensive regulations imposed by governments related to the protection of the environment. Environmental legislation in Western Canada has undergone major revisions that have resulted in environmental standards and compliance becoming more stringent. The Trust is committed to meeting its responsibilities to minimize its impact on the environment wherever it operates, and has instituted a series of controls and procedures with respect to environmental protection that meet the standards of the Environmental Code of Practice published by the Canadian Association of Petroleum Producers. The Trust's plan is to retire approximately 10 percent to 15 percent of its opening ARO annually, using cash flow. All activities that have or could have an environmental impact and all environmental regulations are regularly monitored by the Trust.

Outlook

The outlook for oil and natural gas prices remains strong. For 2006, we are forecasting net capital expenditures of \$400 million to \$500 million which will fund 250 to 300 net wells. Estimated average 2006 production is forecast at 94,000 to 98,000 boe per day. Based on a forecast WTI oil price of US\$58.00 per barrel and an \$8.75 per mcf natural gas price with an exchange rate of \$0.850 CAD/USD for 2006, forecast after-tax cash flow for 2006 is \$1.0 billion to \$1.1 billion.

Sensitivity Analysis

This MD&A includes forward-looking statements (forecasts) under applicable securities laws. These statements are based on assumptions related to, but not limited to, commodity prices, the capital markets, the performance of producing wells and reservoirs, and the regulatory and legal environment. Forward-looking statements are subject to known or unknown risks and uncertainties that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements. The Trust assumes no responsibility to publicly update or revise any forward-looking statements. Sensitivities to selected key assumptions, excluding hedging impacts, are outlined in the table below.

Change of:	Impact on Cash Flow ⁽¹⁾	Impact on Net Income ⁽¹⁾
\$1.00 per barrel of liquids price	16.0	10.4
Per trust unit, basic	0.10	0.06
1,000 barrels per day in liquids production	16.1	7.3
Per trust unit, basic	0.10	0.04
\$0.10 per mcf of natural gas price	7.5	4.9
Per trust unit, basic	0.05	0.03
10 mmcf per day in natural gas production	24.7	10.7
Per trust unit, basic	0.15	0.07
\$0.01 in \$CAD/\$US exchange rate	15.4	10.0
Per trust unit, basic	0.09	0.06

⁽¹⁾ Millions of dollars, except per unit amounts. Cash flow and net income impacts are computed based on 2006 forecast commodity prices and production volumes. The net income impact further assumes that income allocations to the Trust are not adjusted for changes in cash flow, thus impacting the incremental tax rate.

Commitments

We are committed to certain payments over the next five calendar years as follows:

(\$ millions)	2006	2007	2008	2009	2010	Thereafter
Transportation	15.4	8.3	6.4	4.4	1.3	—
Transportation (\$US)	3.4	1.7	1.6	1.6	1.6	7.7
Electricity	3.9	3.9	3.9	3.9	3.9	6.5
Office lease	5.4	4.5	4.2	4.2	2.1	1.4

Equity Instruments

Trust units issued	
As at December 31, 2005 ⁽¹⁾	163,290,013
Issued to distribution reinvestment plan	222,037
Issued to employee savings plan	43,742
As at February 27, 2006	163,555,792
Trust unit rights outstanding	
As at December 31, 2005 ⁽¹⁾	9,447,625
Granted	154,250
Forfeited	(24,000)
As at February 27, 2006	9,577,875

⁽¹⁾ See notes 7 and 8 to the audited consolidated financial statements

Evaluation of Disclosure Controls

The Trust maintains a Disclosure Committee that is responsible for ensuring that all public and regulatory disclosures are sufficient, timely and appropriate, and that disclosure controls and procedures are operating effectively. This Committee includes selected members of senior management, including the Chief Executive Officer, the Chief Operating Officer and the Vice-President, Finance. As at the end of the period covered by this report, under the supervision of the Committee, the design and operating effectiveness of the Trust's disclosure controls were evaluated. According to this evaluation, we have concluded the Trust's disclosure controls and procedures are effective to ensure that any material, or potentially material, information is made known to a member of the Committee and is appropriately included in this report.

Critical Accounting Estimates

The Trust's significant accounting policies are detailed in note 2 to the audited consolidated financial statements. In the determination of financial results, the Trust must make certain significant accounting estimates as follows:

Full Cost Accounting

The Trust uses the full cost method of accounting for oil and natural gas properties. Generally, all costs of exploring and developing oil and natural gas reserves are capitalized and depleted against associated oil and natural gas production using the unit-of-production method based on the estimated proved reserves using forecast pricing.

All Trust reserves were evaluated by GLJ Petroleum Consultants Ltd., an independent engineering firm. In 2005 and 2004, reserves were determined in compliance with National Instrument 51-101. The evaluation of oil and natural gas reserves are, by their nature, based on complex extrapolations and models as well as other significant engineering, capital, pricing and cost assumptions. Reserve estimates are a key component in the calculation of depletion. In addition, reserves are a key component of value in the ceiling test. To the extent that the ceiling amount is less than the carrying amount of property, plant and equipment, a write-down against income must be made.

Asset Retirement Obligations

The Trust applies the Asset Retirement Obligations (ARO) accounting recommendations of the Canadian Institute of Chartered Accountants. The discounted, expected future cost of statutory, contractual or legal obligations to retire long-lived assets are recorded as an ARO liability with a corresponding increase to the carrying amount of the related asset. The recorded ARO liability increases

over time to its future amount through accretion charges to earnings. Revisions to the estimated amount or timing of the obligations are reflected as increases or decreases to the ARO liability. Actual asset retirement expenditures are charged to the ARO liability to the extent of the then recorded liability. Amounts capitalized to the related assets are amortized to income consistent with the depletion or depreciation of the underlying asset. Note 5 to the audited consolidated financial statements details the impact these accounting recommendations had on the audited consolidated financial statements.

Financial Instruments

Financial instruments included in the balance sheets consist of accounts and taxes receivable, current liabilities and the bank loan. The fair values of these financial instruments approximate their carrying amounts due to the short-term maturity of the instruments and the market rate of interest and exchange rates applied to the bank loan.

All of the accounts receivable are with customers in the oil and natural gas industry and are subject to normal industry credit risk. The Trust, from time to time, uses various types of financial instruments to reduce its exposure to fluctuating oil and natural gas prices, electricity costs, exchange rates and interest rates. The use of these instruments exposes the Trust to credit risks associated with the possible non-performance of counterparties to derivative instruments. The Trust limits this risk by transacting only with financial institutions with high credit ratings and by obtaining security in certain circumstances.

The Trust's revenue from the sale of crude oil, natural gas liquids and natural gas are directly impacted by changes to the underlying commodity prices. To ensure that cash flows are sufficient to fund planned capital programs and distributions, costless collars or other financial instruments may be utilized. Collars ensure that commodity prices realized will fall into a contracted range for a contracted sales volume. Forward power contracts fix a portion of future electricity costs at levels determined to be economic by management.

Accounting Changes

Earnings per Share

Effective January 1, 2005, this accounting pronouncement requires the number of incremental shares included in year-to-date diluted earnings per share calculations to be computed using the average market price of shares for the year-to-date period. It also stipulates that contracts that could be settled in cash or shares be assumed settled in shares if share settlement is more dilutive. Shares to be issued upon conversion of convertible instruments with mandatory conversion features would be included in the basic weighted average earnings per share calculation from the date of mandatory conversion. These changes did not materially impact the Trust's reported diluted earnings per unit amounts.

Financial Instruments

Future changes in the fair value of derivative financial instruments will be recorded on the balance sheet with a corresponding unrealized gain or loss in income. For a summary of financial instruments outstanding on December 31, 2005 see note 10 to the audited consolidated financial statements.

Notice Regarding Forward-Looking Statements

This document contains certain forward-looking statements that can generally be identified as such because of the context of the statements. Forward-looking statements may contain words such as "forecasts", "expects", "anticipates", "plans", "intends", "projects", "estimates", or words of a similar nature. Results may differ materially from those expressed or implied by the forward-looking statements as a result of known and unknown risks, uncertainties and other factors.

Such factors include, but are not limited to, the following:

- > Changes in general economic, market and business conditions which will impact demand for and market prices of the Trust's products;
- > The ability of the Trust to implement its business strategy;
- > Availability and cost of borrowing;
- > The ability of the Trust to complete its capital programs;
- > The ability of the Trust to transport its products to market;
- > Potential delays or changes in plans with respect to exploration or development projects;
- > The success of exploration and development activities;
- > The accuracy of reserve estimates;
- > Actions by governmental authorities, government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations);
- > Competitive actions of other entities, including increased competition from other oil and gas producers or from companies that provide alternative sources of energy; and,
- > The occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events directly affecting assets and/or daily operations.

Readers are cautioned that the foregoing list of important factors is not exhaustive. Although the Trust believes that the expectations conveyed by the forward-looking statements are reasonable based on information available on the date the statements are made, events or circumstances could cause actual results to differ materially from those estimated or projected and expressed in, or implied by, these forward-looking statements. The Trust assumes no responsibility to publicly update or revise any forward-looking statements.

Accounting Pronouncements

Financial Instruments, Other Comprehensive Income

This pronouncement, effective for fiscal year-ends beginning on or after October 1, 2006, addresses when to recognize, and how to measure, a financial instrument on the balance sheet and how gains and losses are to be presented. An additional financial statement, entitled "other comprehensive income", will be required. Once implemented, the fair value of financial instruments, designated as hedges, will be included on the balance sheet as an equity item with the related mark-to-market gain or loss recognized in other comprehensive income. Consistent with current practice, financial instruments not designated as hedges will be valued at market with any related gains and losses recognized in net income of the period. As the Trust no longer designates financial instruments as hedges, and immediately recognizes changes in their fair value in net income, this pronouncement is not expected to impact reported results.

Non-Monetary Transactions

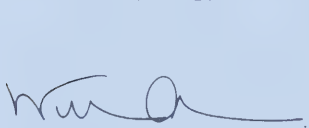
Effective January 1, 2006, this accounting pronouncement requires that non-monetary transactions be measured at fair value unless certain conditions apply and is not expected to affect the Trust's reported results.

Management's Report

The consolidated financial statements of Penn West Energy Trust were prepared by management in accordance with accounting principles generally accepted in Canada. In preparing the consolidated financial statements, management has made estimates because a precise determination of certain assets and liabilities is dependent on future events. The financial and operating information presented in this report is consistent with that shown in the consolidated financial statements.

Management maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded and to facilitate the preparation of relevant, reliable and timely financial records for the preparation of statements.

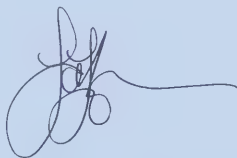
The consolidated financial statements have been examined by the external auditors and approved by the Board of Directors. The Board of Directors' financial statement related responsibilities are fulfilled through the Audit Committee. The Audit Committee is composed entirely of independent directors. The Audit Committee recommends appointment of the external auditors to the Board of Directors, ensures their independence, and approves their fees. The Audit Committee meets regularly with management and the external auditors to discuss reporting and control issues and to ensure each party is properly discharging its responsibilities. The auditors have full and unrestricted access to the Audit Committee to discuss their audit and their related findings as to the integrity of the financial reporting process.



William E. Andrew

President and CEO

February 27, 2006



Todd H. Takeyasu

Vice President, Finance



Derek W. Loomer

Controller

Auditors' Report to Unitholders

We have audited the consolidated balance sheets of Penn West Energy Trust as at December 31, 2005 and 2004 and the consolidated statements of income and accumulated earnings and cash flow for the years then ended. These consolidated financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Calgary, Canada

February 27, 2006

Consolidated Balance Sheets

As at December 31, (\$ millions)	2005	2004
ASSETS		
Current		
Accounts receivable	\$ 214.4	\$ 160.5
Future income taxes	—	25.3
Risk management (note 10)	8.5	—
Other	29.0	19.8
	251.9	205.6
Property, plant and equipment (note 3)	3,715.2	3,661.8
	\$ 3,967.1	\$ 3,867.4

LIABILITIES AND UNITHOLDERS' EQUITY

Current		
Accounts payable and accrued liabilities	\$ 304.1	\$ 306.6
Taxes payable	11.8	11.2
Distributions/dividends payable	50.6	6.7
Stock-based compensation (note 8)	—	71.0
Deferred gain on financial instruments (note 10)	11.9	—
	378.4	395.5
Bank loan (note 4)	542.0	503.1
Asset retirement obligations (note 5)	192.4	180.7
Stock-based compensation (note 8)	—	20.9
Future income taxes	682.1	858.2
	1,416.5	1,562.9
Unitholders' Equity		
Unitholders' capital (note 7)	561.0	515.3
Contributed surplus (note 7)	5.5	—
Accumulated earnings	1,927.2	1,393.7
Accumulated cash distributions (note 9)	(321.5)	—
	2,172.2	1,909.0
	\$ 3,967.1	\$ 3,867.4

See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board:



John A. Brussa
Chairman



James C. Smith
Director

Consolidated Statements of Income and Accumulated Earnings

Years ended December 31, (\$ millions, except per unit amounts)	2005	2004
Revenues		
Oil and natural gas	\$ 1,919.0	\$ 1,521.3
Royalties	(355.0)	(296.1)
	1,564.0	1,225.2
Expenses		
Operating	327.4	300.4
Transportation	22.7	25.6
General and administrative	23.1	16.1
Interest on long-term debt	23.2	17.0
Depletion, depreciation and accretion	437.6	413.1
Equity-based compensation (note 8)	77.2	84.1
Foreign exchange (gain) loss	4.5	(40.4)
Risk management activities (note 10)	3.4	—
	919.1	815.9
Income before Taxes	644.9	409.3
Taxes		
Capital	14.7	10.1
Current income	54.1	17.8
Future income (recovery)	(1.1)	109.6
	67.7	137.5
Net Income	\$ 577.2	\$ 271.8
Net Income per Unit ⁽¹⁾		
Basic	\$ 3.55	\$ 1.68
Diluted	\$ 3.48	\$ 1.65
Accumulated Earnings, Beginning of Period	\$ 1,393.7	\$ 1,148.7
Net income	577.2	271.8
Plan of Arrangement (note 13)	(32.9)	—
Dividends	(10.8)	(26.8)
Accumulated Earnings, End of Period	\$ 1,927.2	\$ 1,393.7

See accompanying notes to the consolidated financial statements.

⁽¹⁾ The 2004 comparative figures have been restated to reflect the conversion ratio of three trust units issued for each Penn West common share pursuant to the Plan of Arrangement.

Consolidated Statements of Cash Flow

Years ended December 31, (\$ millions)	2005	2004
Operating Activities		
Net income	\$ 577.2	\$ 271.8
Depletion, depreciation and accretion	437.6	413.1
Future income taxes (recovery)	(1.1)	109.6
Foreign exchange (gain) loss	4.5	(40.4)
Equity-based compensation (note 8)	77.2	84.1
Risk management activities (note 10)	3.4	—
Payments for surrendered options	(141.6)	(15.6)
Environmental expenditures	(22.6)	(29.5)
Decrease (increase) in non-cash working capital	(1.8)	23.7
	932.8	816.8
Investing Activities		
Additions to property, plant and equipment, net	(456.7)	(865.6)
Decrease (increase) in non-cash working capital	(63.2)	50.0
	(519.9)	(815.6)
Financing Activities		
(Decrease) increase in bank loan	(51.4)	72.6
Issue of equity	23.7	5.2
Realized foreign exchange gain	85.8	28.5
Distributions/dividends paid	(288.4)	(107.6)
Plan of Arrangement costs (note 13)	(36.3)	—
Settlement of future income tax liabilities on conversion	(146.3)	—
Decrease in non-cash working capital	—	0.1
	(412.9)	(1.2)
Change in Cash	—	—
Cash, Beginning of Period	—	—
Cash, End of Period	\$ —	\$ —
Interest paid	\$ 22.9	\$ 17.0
Income and capital taxes paid (recovered)	\$ 241.2	\$ (9.5)

See accompanying notes to the consolidated financial statements

Notes to the Consolidated Financial Statements

(all tabular amounts in \$ millions, except unit and per unit amounts and percentages)

1. Structure of the Trust

On May 31, 2005, Penn West Petroleum Ltd. (the Company) was reorganized into Penn West Energy Trust (the Trust) under a Plan of Arrangement (the Plan) entered into by the Trust and the Company and its shareholders. Shareholders received three trust units for each common share held. On June 2, 2005, the trust units commenced trading on the Toronto Stock Exchange under the symbol "PWT.UN". The Trust was created pursuant to a trust indenture dated April 22, 2005 with CIBC Mellon Trust Company appointed trustee.

The Trust is an open-ended, unincorporated investment trust governed by the laws of the Province of Alberta. The purpose of the Trust is to indirectly explore for, develop and hold interests in petroleum and natural gas properties, through investments in securities of subsidiaries and royalty interests in oil and natural gas properties. The Trust owns 100 percent of the common shares of the Company which carries on the business of the Trust. The activities of the Company are financed through interest-bearing notes from the Trust and third-party debt as described in subsequent notes to the consolidated financial statements.

Pursuant to the terms of a net profits interest agreement (the NPI), the Trust is entitled to payments from the Company equal to essentially all of the proceeds of the sale of production, less certain specified deductions. Under the terms of the NPI, the deductions are discretionary and include the requirement to fund capital expenditures.

Under the terms of the trust indenture, the Trust is required to make distributions to unitholders in amounts equal to the income of the Trust earned from interest on certain notes, the NPI, and any dividends paid on the common shares of the Company, less any expenses of the Trust.

2. Summary of significant accounting policies

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles.

a) Principles of consolidation

The consolidated financial statements, prior to the Plan, included the Company and its subsidiaries. Upon completion of the Plan, the consolidated financial statements have been prepared on a continuity of interests basis with the Trust as the successor to the Company.

The 2005 consolidated financial statements reflect the results of operations and cash flows of the Company and its subsidiaries for the period January 1, 2005 to May 31, 2005 and the results of operations of the Trust and its subsidiaries for the period from June 1, 2005 to December 31, 2005. As a result of the conversion into a trust, certain information included in the consolidated financial statements for prior periods may not be comparable. The consolidated financial statements include the accounts of the Trust and all its wholly owned subsidiaries and partnerships.

b) Other current assets

Other current assets include deposits, prepayments and inventory. Inventories are valued at the lower of cost and net realizable value.

c) Property, plant and equipment

I) CAPITALIZED COSTS

The full cost method of accounting for oil and natural gas operations is followed whereby all costs of acquiring, exploring and developing oil and natural gas reserves are capitalized. These costs include lease acquisition, geological and geophysical, exploration and development and related equipment costs. Proceeds from the disposition of oil and natural gas properties are accounted for as a reduction of capitalized costs, with no gain or loss recognized unless such disposition results in a significant change in the depletion and depreciation rate.

II) DEPLETION AND DEPRECIATION

Depletion and depreciation of resource properties is calculated using the unit-of production method based on production volumes before royalties in relation to total proved reserves as estimated by independent petroleum engineers. Natural gas volumes are converted to equivalent oil volumes based upon the relative energy content of six thousand cubic feet of natural gas to one barrel of oil. In determining its depletion base, the Trust includes estimated future costs to be incurred in developing proved reserves and excludes estimated facility and equipment salvage values and the cost of unevaluated properties. Significant natural gas processing facilities, net of estimated salvage values, are depreciated using the declining balance method over the estimated useful lives of the facilities.

III) CEILING TEST

The recoverability of accumulated costs in a cost centre is assessed based on undiscounted future cash flows from proved reserves, using forecast prices, and the cost of unproved properties. If accumulated costs are assessed to be not fully recoverable, the cost centre is written down to its fair value estimated as the present value of expected future cash flows, using forecast prices, from proved and probable reserves and the value of unproved properties. Expected future cash flows are discounted at the Trust's estimated risk-free rate.

IV) ASSET RETIREMENT OBLIGATIONS

The fair value of legal obligations for property abandonment and site restoration is recognized as a liability on the balance sheet as incurred with a corresponding increase to the carrying amount of the related asset. The recorded liability increases over time to its future amount through accretion charges included in depletion, depreciation and accretion. Revisions to the estimated amount or timing of the obligations are reflected as increases or decreases to the recorded liability. Asset retirement expenditures, up to the recorded liability at the time, are charged to the liability. Amounts capitalized to the related assets are amortized to income consistent with the depletion or depreciation of the underlying asset.

The estimates in ii) and iii) and iv) are based on volumes and reserves calculated based on forecast sales prices, costs and regulations expected at the end of the fiscal year.

d) Joint ventures

Some of the Trust's exploration and development activities are conducted jointly with others. The accounts reflect only the Trust's proportionate interest in such activities.

e) Financial instruments

The Trust has policies and procedures in place with respect to the required documentation and approvals for the use of derivative financial instruments and their use is limited to mitigating market price risk associated with expected cash flows.

The Trust elected to discontinue hedge accounting in 2005. Effective July 1, all financial instruments are accounted for using the fair value method. These financial instruments are recognized on the balance sheet at inception and changes in the fair value of these instruments are recognized in income.

Prior to July 1, 2005 financial instruments that were determined to be hedges were accounted for as a component of the hedged item such as oil prices, natural gas prices, electricity costs or interest. The changes in market values of financial instruments accounted for as hedges were not recognized in the financial statements until the underlying oil or natural gas production, power or interest was realized. Changes in market value of financial instruments determined not to be hedges, not qualifying as a hedge, or no longer effective as a hedge were fully recognized in the financial statements.

f) Enhanced oil recovery

The value of proprietary injectants is not recognized as revenue until reproduced and sold to third parties. The cost of injectants purchased from third parties for miscible flood projects is included in property, plant and equipment. Deferred injectant costs are amortized as depletion and depreciation over the period of expected future economic benefit on a straight-line basis. Costs associated with the production of proprietary injectants are expensed.

g) Foreign currency translation

Monetary items transacted in foreign currency, such as receivables and borrowings, are translated to Canadian dollars at the rate of exchange in effect at the balance sheet date. Non-monetary items, such as property, plant and equipment, are translated to Canadian dollars at the rates of exchange in effect when the transaction occurred. Revenues and expenses denominated in foreign currencies are translated at the average exchange rates in effect during the period. Foreign exchange gains or losses on translation are included in income.

h) Equity-based compensation

The Trust has a new trust unit rights incentive plan that was implemented during the second quarter of 2005. Compensation expense for the plan is based on the fair value of rights issued and amortized over the remaining vesting periods on a straight-line basis. The Black-Scholes option pricing model was used to determine the fair value of rights granted.

The Company had a stock option plan in effect until May 31, 2005. As the plan included a cash settlement alternative, stock-based compensation cost was measured for stock options outstanding at intrinsic value and recognized as an expense over the vesting period. Provision was made for all vested options at the period end plus the portion of future option vestings attributable to the current period. Changes in intrinsic value of outstanding options between the grant date and the measurement date were reflected as stock-based compensation cost. Cash payments made on option exercises were charged against the stock-based compensation liability to the extent that prior provision was made for the payment. Payments in excess of the recorded liability were charged to stock-based compensation cost.

Compensation costs in excess of the recorded liability that were realized due to the cancellation of outstanding stock options as a result of the trust conversion were charged to income as the stock option plan contained a cash settlement alternative.

Costs in respect to the employee trust unit savings plan are expensed as incurred.

i) Revenue recognition

Revenues from the sale of crude oil, natural gas liquids and natural gas are recognized when title passes from the Company to the purchaser. Sales below or in excess of the Company's working interest share of production are recorded as inventory or deferred revenue, respectively.

j) Income taxes

The corporate subsidiaries of the Trust use the liability method of accounting for future income taxes. Timing differences are calculated assuming that the financial assets and liabilities will be settled at their carrying amount. Future income taxes are computed on temporary differences using income tax rates that are expected to apply when future income tax assets and liabilities are realized or settled.

The Trust entity is taxable on income in excess of distributions to unitholders. In accordance with its trust indenture, no provision for future income taxes has been made for timing differences in the Trust as the Trust is required to distribute all of its taxable income to unitholders.

3. Property, plant and equipment

As at December 31,	2005	2004
Oil and natural gas properties, and production and processing equipment	\$ 5,710.4	\$5,241.8
Other	14.0	12.7
	\$ 5,724.4	\$5,254.5
Accumulated depletion and depreciation	(2,009.2)	(1,592.7)
Net book value	\$ 3,715.2	\$3,661.8

Other than the Trust's net share of capital overhead recoveries, no G&A is capitalized. The cost of unevaluated property excluded from the depletion base as at December 31, 2005 was \$259 million (2004 – \$284 million). The depletion and depreciation calculation includes future capital costs to develop proved reserves of \$413 million (2004 – \$397 million).

A ceiling test calculation was performed on the Trust's oil and natural gas property interests at December 31, 2005, which determined that the estimated undiscounted future net cash flows associated with proved reserves, based on forecast prices and escalated costs, exceeded the carrying amount of the Trust's oil and natural gas property interests. Average prices of \$8.46 per mcf for gas and \$54.95 per bbl for liquids were used to calculate the future net revenues.

4. Bank loan

As at December 31,	2005	2004
Bankers' acceptances	\$ 542.0	\$ 154.1
LIBOR advances (2004 – US\$290 million)	—	349.0
	\$ 542.0	\$ 503.1

As at December 31, 2005, the Company had an unsecured, extendable, three-year revolving syndicated credit facility with an aggregate borrowing limit of \$1,170 million that expires May 31, 2008, plus a \$50 million operating credit facility. The credit facility contains provision for stamping fees on Bankers' Acceptances and LIBOR loans, and standby fees on lines that vary depending on certain consolidated financial ratios. Letters of credit totalling \$9 million (2004 – \$9 million), that reduced the amount otherwise available to be drawn on the operating facility, were outstanding at the end of the year.

In 2005, the Company converted its U.S. denominated borrowings to Canadian dollar loans, realizing a foreign exchange gain of \$85.8 million.

5. Asset retirement obligations

Total asset retirement obligations are based upon the present value of the Trust's net share of estimated future costs to abandon and reclaim all wells and facilities. The estimates were made by management and external consultants assuming current technology and enacted legislation.

The total undiscounted, uninflated amount required to settle the asset retirement obligations at December 31, 2005 was \$777 million (2004 – \$737 million). The asset retirement obligation was determined by applying an inflation factor of 1.7 percent (2004 – 1.5 percent) and discounting the inflated amount using a credit-adjusted rate of 7.5 percent (2004 – 7.5 percent) over the expected useful life of the underlying assets, which currently extends up to 50 years into the future with an average life of 22 years.

Changes to asset retirement obligations were as follows:

	2005	2004
Asset retirement obligations at January 1	\$ 180.7	\$ 172.8
Liabilities incurred during the period	9.8	18.6
Liabilities settled during the period	(22.6)	(29.5)
Increase in liability due to change in estimates	3.4	—
Accretion	21.1	18.8
Asset retirement obligations at December 31	\$ 192.4	\$ 180.7

6. Income taxes

As at December 31, future income tax assets (liabilities) arose from temporary differences as follows:

	2005	2004
Property, plant and equipment	\$ (753.7)	\$ (914.0)
Asset retirement obligations	67.0	64.4
Other	4.6	—
Bank loan	—	(16.1)
Stock-based compensation	—	32.8
Capital losses	—	10.7
Valuation allowance on capital losses	—	(10.7)
	\$ (682.1)	\$ (832.9)
Current future income tax assets	\$ —	\$ 25.3
Future income tax liability	(682.1)	(858.2)
	\$ (682.1)	\$ (832.9)

The Trust maintains an income tax status that permits it to deduct distributions to unitholders in addition to other items. Accordingly, no future income tax provision or recovery was made for temporary differences in the Trust. As at December 31, 2005, the book amount of the Trust's assets and liabilities exceeded their tax basis by \$86 million.

The provision for (recovery of) income taxes reflects an effective tax rate that differs from the combined federal and provincial statutory tax rate as follows:

Years ended December 31,	2005	2004
Income before taxes	\$ 644.9	\$ 409.3
Corporate income tax rate	38.4%	39.4%
Computed income tax provision	\$ 247.6	\$ 161.3
Increase (decrease) resulting from:		
Net income attributable to the Trust	(154.3)	—
Non-deductible Crown payments, net	71.0	72.6
Resource allowance	(75.9)	(74.2)
Tax rate reductions	(31.1)	(20.2)
Non-taxable foreign exchange	0.8	(7.5)
Other	(5.1)	(4.6)
Total income taxes	\$ 53.0	\$ 127.4
Current	54.1	17.8
Future (recovery)	(1.1)	109.6
	\$ 53.0	\$ 127.4

7. Unitholders' capital

a) Authorized

i) An unlimited number of voting Trust units, which are redeemable at the option of the unitholder.

ii) An unlimited number of Special Voting Units, which enable the Trust to provide voting rights to holders of any exchangeable shares that may be issued by any direct or indirect subsidiaries of the Trust. Except for the right to vote, the Special Voting Units do not confer any rights.

Trust units are redeemable at any time at the option of the unitholder. The redemption price is equal to the lesser of 95 percent of the closing market price on the date the units were tendered for redemption, 95 percent of the market price for the 10 days immediately after the date the units were tendered for redemption, or 95 percent of the closing market price on the date of redemption. Total redemptions are limited to \$250,000 in any calendar month, subject to waiver at the discretion of the administrator. If the limitation is not waived, the amount payable in excess of the \$250,000 will be settled by the distribution of redemption notes to the redeeming unitholders by the Trust.

The Trust has a Distribution Reinvestment and Optional Trust Unit Purchase Plan (the "DRIP") that provides eligible unitholders the opportunity to reinvest monthly cash distributions into additional units at a potential discount. Units are issued from treasury at 95 percent of the average market price when available. When units are not available from treasury they are acquired in the open market at prevailing market prices.

Unitholders who participate in the DRIP may also purchase additional units, subject to a monthly maximum of \$5,000 and a minimum of \$500. Optional cash purchase units are acquired, without a discount, in the open market at prevailing market prices or issued from treasury at the average market price.

b) Issued

Penn West shareholders received three trust units for each common share held resulting in the issuance of 163,137,018 trust units in exchange for the common shares of Penn West pursuant to the Plan of Arrangement. No special voting units were issued.

Common shares of Penn West Petroleum Ltd.	Shares	Amount
Balance, December 31, 2003	53,692,290	\$ 505.6
Issued on exercise of stock options	176,455	5.2
Liability settlement on stock options exercised for shares	—	4.5
Balance, December 31, 2004	53,868,745	\$ 515.3
Issued on exercise of stock options	488,399	17.0
Issued to employee stock savings plan	21,905	1.8
Cancellation of certificates	(43)	—
Liability settlements on stock options exercised for shares	—	22.0
Balance, May 31, 2005 prior to Plan of Arrangement	54,379,006	\$ 556.1
Exchanged for trust units	(54,379,006)	(556.1)
Balance as at May 31, 2005	—	\$ —
Trust units of Penn West Energy Trust	Units	Amount
Issued to settlor for cash, April 22, 2005	1,250	\$ —
Exchanged for Penn West shares, May 31, 2005	163,137,018	556.1
Issued to employee trust unit savings plan	151,745	4.9
Balance as at December 31, 2005	163,290,013	\$ 561.0

c) Contributed surplus

	2005	2004
Balance, January 1,	\$ —	\$ —
Unit-based compensation expense	5.5	—
Balance as at December 31,	\$ 5.5	\$ —

8. Equity-based compensation

a) Stock option plan

Until May 31, 2005, the Company had a stock option plan for the benefit of its employees and directors. Stock options vested over a five-year period and, if unexercised, expired six years from the date of grant. The stock option plan included a cash payment alternative and stock-based compensation costs were recorded based on changes to the share price at the end of each quarter and any changes to the number of outstanding options. Pursuant to the plan of arrangement, all stock options outstanding on the date of conversion were settled for cash of \$84.77 per share or by issuing shares. The continuity of the compensation liability and outstanding options to the date of cancellation was as follows:

	2005	2004
Liability, January 1,	\$ 91.9	\$ 27.9
Compensation expense provision	71.7	84.1
Cash payments on exercise of stock options	(141.6)	(15.6)
Liability settlements on stock options exercised for shares	(22.0)	(4.5)
Liability, December 31,	—	91.9
Current portion	—	71.0
Long-term portion	—	20.9
	\$ —	\$ 91.9

Penn West stock options	Number of Stock Options	Weighted Average Exercise Price
Outstanding, January 1, 2005	3,728,980	\$ 39.00
Granted	82,600	79.51
Exercised for common shares	(488,399)	34.72
Settled for cash	(3,212,931)	40.51
Forfeited	(110,250)	44.26
Outstanding, May 31, 2005	—	\$ —

b) Trust unit rights incentive plan

In May 2005, the Trust implemented a unit rights incentive plan that allows the Trust to issue rights to acquire trust units to directors, officers, employees and service providers. The number of trust units reserved for issuance shall not at any time exceed 10 percent of the aggregate number of issued and outstanding trust units of the Trust. Unit right exercise prices are equal to the market price for the trust units based on the five-day weighted average market price prior to the date the unit rights are granted. If certain conditions are met, the exercise price per unit is reduced by deducting from the grant price the aggregate of all distributions, on a per unit basis, paid by the Trust after the grant date. Rights granted under the plan vest over a five-year period and expire six years after the date of the grant.

Trust unit rights	Number of Unit Rights	Weighted Average Exercise Price
Granted	10,045,325	\$ 29.73
Forfeited	(597,700)	28.46
Balance before reduction of exercise price	9,447,625	\$ 29.81
Reduction of exercise price for distributions paid	—	(1.36)
Outstanding, December 31, 2005	9,447,625	\$ 28.45
Exercisable, December 31, 2005	—	\$ —

The Trust recorded compensation expense of \$5.5 million for the period from implementation to December 31, 2005. The compensation expense is based on the fair value of rights issued and is amortized over the remaining vesting periods on a straight-line basis. The Black-Scholes option pricing model was used to determine the fair value of trust unit rights granted with the following weighted average assumptions:

Seven months ended December 31,	2005
Average fair value of trust unit rights granted (per unit)	
Directors and officers	\$ 6.50
Other employees	\$ 6.13
Expected life of trust unit rights (years)	
Directors and officers	5.0
Other employees	4.5
Expected volatility (average)	16%
Risk-free rate of return (average)	3.4%
Expected distribution rate	nil ⁽¹⁾

- ⁽¹⁾ The expected distribution rate is assumed to be nil as it is expected that future distributions will result in a reduction to the exercise price of trust unit rights.

c) Employee trust unit savings plan

The Trust has an employee trust unit savings plan for the benefit of all employees. Under the savings plan, employees may elect to contribute up to 10 percent of their salary and contributions are used to fund the acquisition of trust units. The Trust matches employee contributions at a rate of \$1.50 for each \$1.00 contributed. Trust units may be issued from treasury at the five-day weighted average month-end market price or purchased in the open market. No units have been purchased in the open market subsequent to the conversion.

Prior to the trust conversion, the Company had a stock savings plan with essentially the same terms as the trust unit savings plan. During 2005, 20,355 employer contribution shares (equivalent to 61,065 trust units) were purchased in the open market at an average price of \$81.48 per share (\$27.16 per equivalent trust unit) and a total cost of \$1.7 million, and 21,905 shares (equivalent to 65,715 trust units) were issued from treasury. In 2004, all employee contribution shares and 87,787 employer contribution shares (equivalent to 263,361 trust units) were purchased in the open market. The employer contribution shares were purchased at an average price of \$66.90 per share (\$22.30 per equivalent trust unit) and a total cost of \$5.9 million.

9. Distributions payable to unitholders

Under the terms of the Trust indenture, the Trust is required to make distributions to unitholders in amounts equal to the income of the Trust earned from interest on certain notes, the NPI, and any dividends paid on the common shares of the Company, less any expenses of the Trust. Distributions may be monthly or special and in cash or in trust units at the discretion of the Board of Directors. Distributions payable to unitholders is the amount declared and payable by the Trust.

Accumulated cash distributions

	2005
Accumulated cash distributions, beginning of period	\$ —
Distributions declared	321.5
Accumulated cash distributions, end of period	\$ 321.5
Distributions per unit ⁽¹⁾	\$ 1.97
Accumulated cash distributions per unit, beginning of period	—
Accumulated cash distributions per unit, end of period	\$ 1.97

⁽¹⁾ Distributions per unit are the sum of the per unit amounts declared monthly to unitholders.

10. Financial instruments

Financial instruments included in the balance sheets consist of accounts and taxes receivable, current liabilities and the bank loan. The fair values of these financial instruments approximate their carrying amounts due to the short-term maturity of the instruments and the market rate of interest and exchange rates applied to the bank loan.

All of the accounts receivable are with customers in the oil and natural gas industry and are subject to normal industry credit risk. The Trust, from time to time, uses various types of financial instruments to reduce its exposure to fluctuating oil and natural gas prices, electricity costs, exchange rates and interest rates. The use of these instruments exposes the Trust to credit risks associated with the possible non-performance of counterparties to derivative instruments. The Trust limits this risk by transacting only with financial institutions with high credit ratings and by obtaining security in certain circumstances.

The Trust's revenue from the sale of crude oil, natural gas liquids and natural gas are directly impacted by changes to the underlying commodity prices. To ensure that cash flows are sufficient to fund planned capital programs and distributions, costless collars, or other financial instruments, may be utilized. Collars ensure that commodity prices realized will fall into a contracted range for a contracted sales volume. Forward power contracts fix a portion of future electricity costs at levels determined to be economic by management.

Variations in interest rates directly impact interest costs. From time to time, the Trust may increase the certainty of future interest rates using financial instruments to swap floating interest rates to fixed rates.

Crude oil sales and certain bank loans are referenced to or denominated in U.S. dollars. Accordingly, realized crude oil prices and debts in Canadian dollars are directly impacted by CAD/USD exchange rates. From time to time, the Trust may use financial instruments to fix future exchange rates.

As at December 31, 2005, the Trust had the following financial instruments outstanding:

	Notional Volume	Remaining Term	Pricing	Market Value (\$ millions)
Crude Oil				
WTI Costless Collars	20,000 bbls/d	Jan/06 – Dec/06	\$US 47.50 to \$67.86/bbl	\$ (22.1)
Natural Gas				
AECO Costless Collars	46,300 mcf/d	Jan/06 – Mar/06	\$8.64 to \$16.69/mcf	0.2
AECO Costless Collars	46,300 mcf/d	Jan/06 – Oct/06	\$8.64 to \$16.25/mcf	2.1
AECO Costless Collars	18,500 mcf/d	Jan/06 – Oct/06	\$9.72 to \$17.28/mcf	3.3
AECO Costless Collars	23,100 mcf/d	Apr/06 – Sept/06	\$9.07 to \$15.12/mcf	0.7
AECO Costless Collars	9,300 mcf/d	Apr/06 – Sept/06	\$9.18 to \$15.39/mcf	0.8
AECO Costless Collars	13,400 mcf/d	Oct/06 – Dec/06	\$9.18 to \$17.39/mcf	0.2
Electricity				
Alberta Power Pool Swaps	60 MW	2006	\$42.25 to \$43.15/MWh	16.6
Alberta Power Pool Swaps	35 MW	2007	\$46.00/MWh	6.7

Effective July 1, 2005, the Trust elected to discontinue the designation of commodity and power financial instruments as hedges, choosing to account for these instruments using the fair value method. In accordance with the accounting recommendations, the fair value of power contracts at July 1, 2005 in the amount of \$16.7 million was recorded as a deferred gain and will be recognized into income over the life of the contracts. Future changes in the fair value of commodity and power contracts will be recorded on the balance sheet with a corresponding unrealized gain or loss in income.

The following table reconciles the changes in the fair value of financial instruments no longer designated as hedges:

Risk Management:	
Balance June 30, 2005	\$ –
Deferred gain at June 30	16.7
Unrealized gain on financial instruments	(8.2)
Fair value, December 31, 2005	\$ 8.5
Deferred Gain on Financial Instruments:	
Balance June 30, 2005	\$ –
Deferred gain at June 30	(16.7)
Amortization	4.8
Ending balance, December 31, 2005	\$ (11.9)

11. Per unit amounts

The Trust follows the treasury stock method to compute the dilutive impact of unit rights. The treasury stock method assumes that the proceeds received from the pro-forma exercise of in-the-money trust unit rights are used to purchase trust units at average market prices.

The Trust adopted the new earnings per share ("EPS") accounting recommendations effective January 1, 2005. The number of incremental shares included in diluted EPS is computed using the average market price of common shares for the year-to-date period. In addition, contracts that could be settled in cash or common shares are assumed settled in common shares if share settlement is more dilutive. Shares to be issued upon conversion of convertible instruments with a mandatory conversion feature would be included in the basic weighted average EPS calculation from the date when conversion becomes mandatory. These changes did not materially impact the Trust's reported diluted EPS amounts.

The weighted average number of trust units used to calculate per unit amounts was:

Years ended December 31,	2005	2004
Basic	162,632,127	161,458,452
Diluted	165,878,364	164,408,871

12. Change in non-cash working capital

Changes in non-cash working capital items increased (decreased) cash and cash equivalents as follows:

Years ended December 31,	2005	2004
Accounts receivable	\$ (53.9)	\$ (18.9)
Taxes receivable	—	26.3
Other current assets	(9.2)	(3.3)
Accounts payable and accrued liabilities	(2.5)	58.5
Taxes payable	0.6	11.2
	\$ (65.0)	\$ 73.8
Operating activities	\$ (1.8)	\$ 23.7
Investing activities	(63.2)	50.0
Financing activities	—	0.1
	\$ (65.0)	\$ 73.8

13. Plan of Arrangement costs

Effective May 31, 2005, the Company commenced operations as an oil and gas income trust pursuant to a plan of arrangement approved by the shareholders on May 27, 2005. Certain amounts, related to the Plan of Arrangement, were charged to accumulated earnings:

Rate differences on income taxes paid	\$ 13.3
Incremental capital taxes	13.4
Financial advisor fees	5.6
Filing fees, communication, professional fees and other	4.0
Tax benefit on fees	(3.4)
	\$ 32.9

In addition, the Trust conversion resulted in a short income tax year that accelerated \$146.3 million of cash income taxes as a significant amount of Penn West's taxable income was earned in a partnership.

14. Related-party transactions

The Trust incurred \$2.1 million (2004 – \$0.8 million) of legal expenses with a law firm of which one partner is a director of the Trust.

Our Employees

Trevor Aadland
Ray Abt
Lorraine Ahearn
John Alexander
Myron Andersen
Val Anderson
William Andrew
Brian Antoni
Edward Armagost
Kristine Arthur
William Arthur
John Artym
Jessica Au Yeung
Shaun Axworthy
Henry Babayan
Aaron Babiak
Kevin Bachman
August Baier
James Baier
Jamie Baier
Mary Ann Bailey
Cory Bain
Robert Bak
Marjorie Baker
Christine Ball
Leona Ballman
Glenn Bamber
Tim Barich
Deanna Barrell
Kelly Batten
Curtis Bazylnski
Stephen Beairsto
Allison Beaton
Linda Beaton
David Becker
Ginnette Becker
Lynda Becker
Miguel Belarde
James Bell
Harold Bellerose
Shawn Bennett
Craig Berger

Robert Berki
Alan Berry
Billie Berry
Paula Bica
Jeff Biggin
Kenneth Bills
Rhett Binding
Jenna Bingeman
Darrel Bird
Morley Birnie Browne
Corey Bitzer
Michael Blair
Jaclyn Bock
Gordon Borle
Wayne Borton
Kevin Bossert
Brett Bouchard
Jane Bouey
Daniel Bounds
Maurice Bourgeois
Vivian Bredin
Michael Breward
Clifford Brigley
Laurence Broos
Jean Brule
Wayne Brzus
Paul Bullock
Carl Bur
James Burgess
Janet Burns
Steven Cacka
Lynn Callsen
Heather Campbell
Nadine Campbell
Leslie Carlyle-Ebert
Neil Carnell
Murrey Carpendale
Philip Carpentier
Allan Carter
Michael Carteri
Craig Caseley
Cory Cavener

Ann Ceccanese
Louis Chabot
Sylvia Chan
Barclay Charlton
Kun Cheang
Thomas Chenard
Mitchell Chibri
Dennis Choi
Danny Chow
Louis Chow
Gloria Choy
Kurtis Christianson
Linda Chu
Jeffary Chung
Barry Chykerda
Audrey Clark
Alan Clarke
Eric Clarke
Barry Clarkson
Robert Clayson
Wendy Clermont
Nadine Closs
Andrew Connolly
Philip Connolly
Timothy Connolly
Thomas Cookson
Jason Cooper
Sandra Cooper
Ameeta Cordell
Colleen Cornish
Don Cote
Rachel Cote
Wendy Couronne
Dali Courtright
Darcy Crawford
Tammy Cretney
Douglas Cromer
David Crosley
Jeff Cross
Greg Cunliffe
Harvey Cunningham
Randy Cuthbert



Tara Cybulsky
Darren Cygan
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Kenneth Erker
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Barbara Finley
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Gregory Foofat
Jackson Ford
Dean Forrester
Codey Foss
Harvey Foss
Shannon Foster
Wilfred Foster



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Neil Gallant
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Shane Georget
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Moninder Gill
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James Young
Corey Zadko
Rebecca Zhang
Perry Zich
Travis Zubot
Sean Zunti

In Memory
In 2005 and in early 2006, we were deeply saddened by the loss of Glen Lee and Danny Nicolls. We extend our thoughts and prayers to their families and friends.

Summary Information – Five Year Summary

Years ended December 31,	2005	2004	2003	2002	2001
FINANCIAL					
(\$ millions, except unit and per unit ⁽¹⁾ amounts and payout ratio)					
Gross revenues	\$ 1,919.0	\$ 1,521.3	\$ 1,394.2	\$ 1,008.4	\$ 1,096.6
Cash flow ⁽²⁾	1,184.6	866.7	812.8	463.5	612.9
Basic per unit	7.28	5.37	5.04	2.90	3.91
Diluted per unit	7.14	5.28	4.97	2.83	3.79
Net income	577.2	271.8	446.6	165.2	248.1
Basic per unit	3.55	1.68	2.77	1.03	1.58
Diluted per unit	3.48	1.65	2.73	1.01	1.53
Capital expenditures	456.7	865.6	608.1	573.3	633.5
Total assets	3,967.1	3,867.4	3,309.6	2,933.3	2,507.8
Bank indebtedness	542.0	503.1	442.4	598.4	556.3
Unitholders' equity	2,172.2	1,909.0	1,654.3	1,314.6	1,128.9
Distributions declared	321.5	—	—	—	—
Distributions per unit	1.97	—	—	—	—
Payout ratio (%) ⁽³⁾	43	—	—	—	—
Dividends declared					
Quarterly	10.8	26.8	6.7	—	—
Special	—	—	80.7	—	—
Total	\$ 10.8	\$ 26.8	\$ 87.4	\$ —	\$ —
Trust units outstanding at year-end (000s)					
Basic	163,290	161,607	161,076	161,199	158,169
Basic plus rights	172,738	172,794	173,757	176,214	174,327
Market value per trust unit					
High	\$ 38.53	\$ 27.33	\$ 16.50	\$ 14.91	\$ 15.08
Low	25.23	15.86	11.92	10.92	10.10
Close	\$ 37.99	\$ 26.42	\$ 16.05	\$ 13.67	\$ 11.80
OPERATING					
Production					
Light oil and NGL production (bbls/day)	33,137	34,943	35,479	33,822	29,375
Light oil and NGL price (\$/bbl)	\$ 62.59	\$ 42.04	\$ 38.40	\$ 34.81	\$ 34.92
Conventional heavy oil production (bbls/day)	18,705	18,136	10,853	10,211	9,509
Conventional heavy oil price (\$/bbl)	\$ 35.71	\$ 31.73	\$ 28.70	\$ 26.10	\$ 20.24
Combined liquids production (bbls/day)	51,842	53,079	46,332	44,033	38,884
Combined liquids price (\$/bbl)	\$ 52.89	\$ 38.52	\$ 36.13	\$ 32.79	\$ 31.33
Natural gas production (mmcf/day)	287.8	316.3	331.3	332.7	330.3
Natural gas price (\$/mcf)	\$ 8.74	\$ 6.68	\$ 6.48	\$ 3.97	\$ 5.41
Reserves (proved plus probable) at year-end					
Oil and NGL (mmbbls)	241	240	222	249	229
Natural gas (bcf)	698	761	813	1,013	1,071
Wells drilled (gross)					
Natural gas	150	209	307	209	274
Oil	119	195	337	112	118
Dry	18	35	106	44	61
Total wells drilled	287	439	750	365	453
UNDEVELOPED LAND HOLDINGS					
Western Canada (000 acres)					
Gross	4,390	6,058	5,538	4,402	3,672
Net	4,142	5,767	5,313	4,158	3,381
Average working interest (%)	94	95	96	94	92

⁽¹⁾ The 2004 and prior years' comparative figures have been restated to reflect the conversion ratio of three trust units issued for each Penn West common share pursuant to the Plan of Arrangement.

⁽²⁾ Cash flow is a non-generally accepted accounting principles measure. For the Trust's calculation of cash flow, refer to Management's Discussion and Analysis.

⁽³⁾ Based on cash flow for the seven months subsequent to converting to an energy trust.

Summary Information – Quarterly Summary

Three months ended	2005				2004			
	Mar. 31	June 30	Sept. 30	Dec. 31	Mar. 31	June 30	Sept. 30	Dec. 31
FINANCIAL								
(\$ millions, except per unit ⁽²⁾ amounts)								
Gross revenues	\$ 405.3	\$ 424.2	\$ 535.0	\$ 554.5	\$ 346.1	\$ 390.4	\$ 384.3	\$ 400.5
Cash flow ⁽¹⁾	260.1	257.0	334.9	332.6	181.2	211.2	236.5	237.8
Basic per unit	1.61	1.58	2.06	2.03	1.13	1.31	1.46	1.47
Diluted per unit	1.58	1.49	2.04	2.03	1.11	1.29	1.44	1.44
Net income	66.9	59.7	209.5	241.1	61.0	65.5	76.7	68.6
Basic per unit	0.41	0.37	1.29	1.48	0.38	0.41	0.48	0.42
Diluted per unit	0.41	0.34	1.27	1.46	0.37	0.40	0.47	0.42
Distributions declared	—	42.4	127.3	151.8	—	—	—	—
Distributions per unit	\$ —	\$ 0.26	\$ 0.78	\$ 0.93	\$ —	\$ —	\$ —	\$ —
OPERATING								
Light oil and NGL production (bbls/day)	34,219	32,011	33,101	33,227	37,277	34,624	33,370	34,524
Light oil and NGL price (\$/bbl)	\$ 56.00	\$ 59.05	\$ 70.94	\$ 64.28	\$ 37.72	\$ 39.80	\$ 42.37	\$ 48.57
Conventional heavy oil production (bbls/day)	18,943	18,622	18,533	18,726	13,968	19,692	19,596	19,257
Conventional heavy oil price (\$/bbl)	\$ 28.06	\$ 31.22	\$ 48.60	\$ 34.95	\$ 28.50	\$ 30.17	\$ 37.37	\$ 29.89
Combined liquids production (bbls/day)	53,162	50,633	51,634	51,953	51,245	54,316	52,966	53,781
Combined liquids price (\$/bbl)	\$ 46.04	\$ 48.81	\$ 62.92	\$ 53.71	\$ 35.21	\$ 36.30	\$ 40.52	\$ 41.88
Natural gas production (mmcf/day)	289.1	295.7	289.0	277.5	312.0	329.8	316.0	307.4
Natural gas price (\$/mcf)	\$ 7.11	\$ 7.41	\$ 8.88	\$ 11.66	\$ 6.41	\$ 7.03	\$ 6.43	\$ 6.83

⁽¹⁾ Cash flow, cash flow per unit-basic and cash flow per unit-diluted are non-GAAP measures. Refer to the calculation of cash flow in the MD&A.

⁽²⁾ Per unit amounts prior to June 30, 2005 have been restated to reflect the conversion ratio of three trust units issued for each Penn West common share pursuant to the Plan of Arrangement to effect the trust conversion on May 31, 2005.

Abbreviations

bbl	barrel (oil or natural gas liquids)
mmbbls	million barrels
bbls per day or	
bbls/day or bbls/d	barrels per day
boe	barrels of oil equivalent (based on 6 mcf of natural gas equals one barrel of oil)
mmboe	million barrels of oil equivalent
mcf	thousand cubic feet (natural gas)
mmcf	million cubic feet
mmcf per day	million cubic feet per day
NGL	natural gas liquids
GJ	gigajoule
bcf	billion cubic feet
API	American Petroleum Institute
TSX	Toronto Stock Exchange
WTI	West Texas Intermediate
MW	megawatt
MWh	megawatt-hour

Conversions of Units

Imperial	Metric
1 ton	0.907 tonnes
1,102 tons	1 tonne
1 acre	0.40 hectares
2.5 acres	1 hectare
1 bbl	0.159 cubic metres
6.29 bbls	1 cubic metre
1 mcf	28.2 cubic metres
.035 mcf	1 cubic metre
1 mile	1.61 kilometres
0.62 miles	1 kilometre

Unless otherwise stated, all financial sums are stated in Canadian dollars.

Investor Information

Officers

William Andrew

President and CEO

David Middleton

Executive Vice President and COO

Thane Jensen

Senior Vice President, Exploration
and Development

Gregg Gegunde

Vice President, Development

Eric Obreiter

Vice President, Production

Todd Takeyasu

Vice President, Finance

Kristian Tange

Vice President, Business Development

William Tang Kong

Vice President, Corporate Development

Anne Thomson

Vice President, Exploration

Directors

John A. Brussa ⁽²⁾⁽⁴⁾

Chairman
Calgary, Alberta

William E. Andrew

Calgary, Alberta

Thomas E. Phillips ⁽¹⁾⁽²⁾⁽³⁾⁽⁴⁾⁽⁵⁾

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Calgary, Alberta

Murray R. Nunns ⁽¹⁾⁽²⁾⁽³⁾⁽⁵⁾

Calgary, Alberta

George H. Brookman ⁽¹⁾⁽⁴⁾⁽⁵⁾

Calgary, Alberta

Notes:

- ⁽¹⁾ Member of the Audit Committee
- ⁽²⁾ Member of the Human Resources and Compensation Committee
- ⁽³⁾ Member of the Reserves Committee
- ⁽⁴⁾ Member of the Governance Committee
- ⁽⁵⁾ Member of the Health, Safety and Environment Committee

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Thackray Burgess

Calgary, Alberta

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Calgary, Alberta

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Royal Bank of Canada

The Bank of Nova Scotia

Bank of Montreal

Bank of Tokyo-Mitsubishi (Canada)

Alberta Treasury Branches

Sumitomo Mitsui Banking Corporation
of Canada

BNP Paribas (Canada)

Soci te Generale

HSBC Bank Canada

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Notes to Reader

1) This document contains forward-looking statements (forecasts) under applicable securities laws. Forward-looking statements are necessarily based upon assumptions and judgements with respect to the future including, but not limited to, the outlook for commodity markets and capital markets, the performance of producing wells and reservoirs, and the regulatory and legal environment. Many of these factors can be difficult to predict. As a result, the forward-looking statements are subject to known or unknown risks and uncertainties that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements.

2) All dollar amounts outlined in this document are expressed in Canadian dollars unless noted otherwise.

3) Where applicable, natural gas has been converted to barrels of oil equivalent (boe) using a conversion rate of 6 mcf of natural gas to 1 boe. However, this could be misleading if used in isolation. A boe conversion of 6:1 is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent a value equivalency at the wellhead.



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